Chapter 7:
Price Projections and Marginal Cost:
The Foundation of Prices and Cash Flow Forecasts

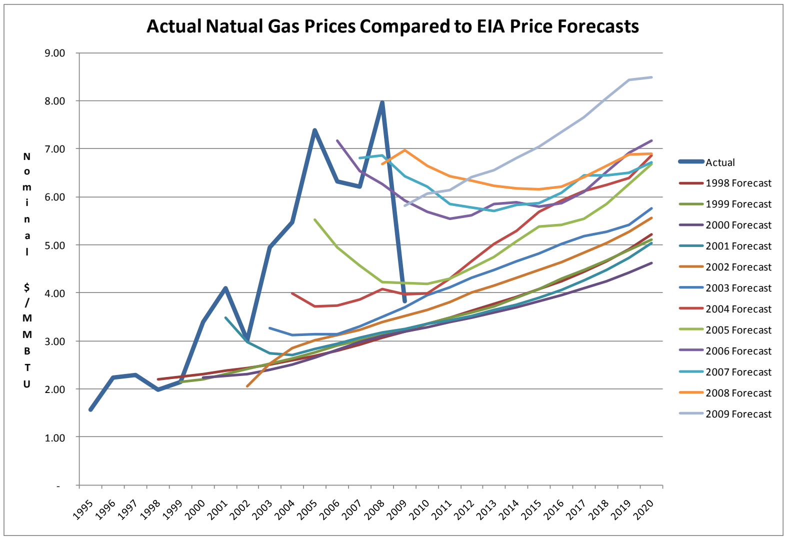
Introduction – Economic Building Blocks of Price Forecasts

As is apparent from earlier chapters, valuation theory tends to concentrate on things like beta, volatility, option pricing models and the weighted average cost of capital. However, the most important task in valuation will always be projecting revenues, operating expenses and capital expenditures that drive operating cash flow. Developing formulas or guidelines that can be used to forecast cash flows in different industries is all but impossible. Coming up with ways to use translate fundamental economic principles into supportable assumptions that can be used in financial modeling analysis is far less defined than all of the techniques used to come up with value through computing free cash flow, discounting cash flows and other issues that were discussed in earlier chapters. The general theme of this chapter is attempting to measure how low prices or general directions for prices over the long term can be guided by some basic economic principles revolving around marginal cost, surplus capacity and demand elasticity. The idea in this chapter is to provide some general modeling ideas to guide long-term forecasts and to describe general economic concepts that can be used in qualitative assessments of risk analysis regarding possible price movements.

The essential component of forecasting cash flow involves creating an outlook for value drivers such as product prices, quantity sold in an industry, market share, the breakdown between variable and fixed costs and the cost of new capital equipment. When creating corporate finance analysis, developing a framework that evaluates capacity in a market, demand growth, market share and product prices is generally the most important component of the analysis and the part that requires most creativity. Out of all of the value drivers, projection of the product price is often the most important and most difficult input. Incorrect estimates of future prices – particularly optimistic prices -- that do not consider how fundamental supply and demand conditions can cause dramatic change in price levels and price volatility have caused many valuation analyses to go very wrong. Virtually all of the mistakes in Chapter 1 involved incorrect estimates of price driven by supply and demand in one way or another. In the case of AES Drax, the price of electricity crashed because of surplus supply and a more competitive industry structure; for Eurotunnel, the increase in capacity caused by the tunnel itself resulted in a price war with the ferries; the telecom meltdown was driven by massive additions of capacity that were not mirrored by increases in demand; problems with the Dabhol plant were driven by not paying enough attention to the inherent cost structure of the power plant; and, errors made in the early 2000's for residential U.S. home prices as well as the mid 1980's for commercial properties and in the mid 1990's in East Asia ultimately led to defaults on real estate loans and the subsequent financial crises. The question addressed in this chapter is how one could have come up with approaches to gauge the potential movement in these prices when developing valuation analyses.

Given historic changes in the volatility and trends of various different prices that drive the value of capital intensive investments -- the price of copper, steel, oil, natural gas, ship charter rates, aluminum, real estate, air freight and telecommunication bandwidth for example -- developing a reasonable forecast over the long lifetime of a capital intensive project may seem to be an utterly hopeless task. A graph of actual and projected oil prices presented in Chapter 4 illustrated dramatic mistakes in forecasting oil prices made by experts hired by the Energy Information Agency. With all of the underlying data on worldwide reserves, trends in demand for oil, judgments about geopolitical events and other factors that drive oil prices, the forecasts were dramatically off the mark. And oil prices are of course not the only forecasts that have been hopeless. A graph actual natural gas prices relative to various forecasts made by the EIA shown below illustrates a similar dramatic underestimation prior to 2009 followed later by forecasts that overshot

the actual price.[1] In the case of natural gas prices, better forecasts could have been made by estimating a simple time trend along with provisions for mean reversion (for example, changes in technology that have allowed development of shale gas were not predicted in the forecasts.) Given the difficulties in making forecasts of economic variables, it is tempting to throw your hands in the air and assert, as does Nicholas Taleb, that anybody who makes a forecast of economic variables such as prices is engaging in fraud.[2] Our problem in valuation is that if you do not make a price forecast, you are left with no basis to make a quantitative assessment of the value of an investment.



This chapter describes marginal cost principles and practical techniques that can be used to measure and forecast underlying drivers of prices. The discussion begins with a review of some fundamental economic theory involving marginal cost principles and then considers various items that must be measured in order to build forecasts of marginal cost. The subjects include: (1) the definition of marginal cost in capital intensive industries; (2) calculation of carrying charges that underlie the capital cost component of marginal cost; (3) the theory of how marginal capital costs translate into prices where diverse production capacity has different cost and efficiency characteristics; (4) derivation of the volatility in short-run marginal costs which is driven by variability in input prices, changes in efficiency and demand uncertainty; and (5) the mathematics of deriving long-term marginal cost in equilibrium. Working through these concepts provides a foundation for establishing the price drivers in cash flow models that can be used in alternative base case, downside and upside scenarios. The analysis can also be used to develop volatility, mean reversion and other parameters for stochastic models.

Marginal Cost Theory

Asserting that one can build is some kind of complicated econometric model in making price forecasts or estimating price volatility is both dangerous and arrogant. One of the ideas presented in this chapter is that a better alternative to engaging in price forecasts derived from statistical analysis is to focus on understanding the underlying economic cost of the product in question -- the long-term marginal cost. The simple notion that prices cannot indefinitely remain substantially below or above marginal cost can be used to establish a long-term outlook (this works unless there are significant barriers to entry or some other king of market interventions such as government regulation.) Were prices to remain above or below cost and not move toward marginal cost, there would be never-ending over-supply or never-ending shortages. To illustrate how this simple idea works, consider again the housing price bubble that preceded the financial crisis. When sub-prime and other loans were being made at loan to value ratios of

[1] Reference: EIA website
[2] Reference: Black Swan, Taleb, Nicholas.

more than 100% on the basis of inflated real estate values, assessment of value derived from the underlying cost of building materials, land and labor would have yielded a very different answer than the practice of making appraisals from the inflated prices in other comparative transactions. With hindsight we now know that it would have been much better to assess the prices by evaluating the long-run marginal cost of building a new home.

In considering the usefulness of applying marginal cost principles in valuation analyses, some will surely argue that the investigation of marginal cost for the purpose of evaluating prices is not very useful since prices are often driven by speculation, market sentiment, gaming behavior and other factors not related to cost. For example, when oil price reached $147 per barrel in 2008, this price level was difficult to explain the price from supply and demand factors -- despite elaborate speeches made by fast talking experts on television who spoke about demand in China and India and the decline in worldwide oil reserves. At that time, economic analysis of the marginal cost of production in the Gulf of Mexico or even the oil sands in Canada which was well below the very high prices did not seem to have to do much with the very high level of prices. In any industry, prices virtually never exactly equal marginal cost for any good or service at any point in time, especially in the midst of a bubble. Yet despite the real world diversion between prices and cost, economic theory can still be valuable in providing a foundation for the analytical models that otherwise would be black boxes driven by arbitrary statistical parameters. Stated another way, if economic analysis of marginal cost gives you 75% of the answer, it would be silly to throw this information away instead of building on the 75% and finding other approaches to derive the last 25% piece of the puzzle. In sum, while competitive markets have not and will probably never work in a perfect manner where prices precisely equate to marginal cost, marginal cost influences prices more than anything else and a solid understanding of marginal cost is essential for understanding the movement of prices over time.

The reason marginal cost is relevant in making price forecasts is because of the simple idea that businesses, consumers and other entities make decisions on the basis of how an action will affect their future well being. When both consumers and producers make decisions through evaluating how much they can profit if they change their consumption and production behavior, then prices should approximate the short-run marginal cost. (This assumes markets are competitive and there are no major limits on the entry of firms into the market.) If prices are above the incremental cost of producing one more unit, suppliers who have costs near to the marginal cost will want to produce more, leaving an excess of production in the market. In this situation, prices must fall so that surplus in the market will clear and producers will produce less. On the other hand, if prices are below the marginal cost of producing an additional unit, suppliers with relatively high costs will not want to produce. This will create shortages in the market and prices must rise to promote supply that will alleviate the shortage. The implication of all this very basic economic theory is that we need to find the marginal cost if we want to find the stable level of prices. Similar arguments demonstrating that marginal cost should equal price can be made with respect to demand. In situations where the price is below marginal cost, surplus inventory will accumulate and prices must fall prompting increased consumer demand to absorb the over-supply. The converse is true when price is above marginal cost where prices must increase to ameliorate the shortage.

While the proposition that prices should equal marginal cost is one of the most fundamental principles in economics, defining marginal costs in a practical way that can be useful for value driver analysis in cash flow forecasting is a much more complex matter. Generally speaking, marginal cost can be defined as the change in the opportunity cost of a good or service (the true cost which is opportunity cost), divided by a small change in consumption or production of that good or service. Opportunity cost is measured in terms of the cost of other things that are avoided if a small amount of the product is produced. As capital investment from investors is required to produce just about anything and since profits must be earned on money that is used to finance capital to prompt investment, part of the opportunity cost includes profit on investment. In terms of a formula, marginal cost can be defined as:

Marginal Cost = Small Change in Opportunity Cost / Small Change in Units Consumed

For many items, both the opportunity costs of changing production – the numerator in the marginal cost calculation -- and the units of consumption that cause costs to change on the margin – the denominator –

are not obvious to measure. This means that in order to use marginal cost as a guide for analysis of prices, the first task is to carefully define marginal cost for the product that the subject of the cash flow forecast. For example, in using marginal cost to evaluate the price of copper, one question is whether opportunity cost includes the benefits from finding gold and silver that are often also extracted when copper is mined. Assuming the unit of production (the denominator) is only copper, the variable opportunity cost of extracting an additional gram of copper and ore generally includes a credit for the value of gold and silver that is part of the mining process. Another problem is how to account for capital costs associated with building the copper mine in the equation. If the change in opportunity cost only included variable costs of extracting and processing the copper, and if each mine in the world had the same cost structure, then the marginal cost would not cover opportunity costs associated with capital investments and no sensible investor would ever again want to invest in a new mine. This implies that marginal cost should include something to account for the fact that the copper would not be mined if prices did not cover the cost of the capital equipment used to process the ore as well as the cost of the infrastructure used to construct a new mine. Similar issues that make the definition of marginal cost tricky arise in measuring the cost of airplane trips. In measuring the marginal cost of an airplane trip from the perspective of an airline company, the units consumed may be defined as the seat on a plane, additional plane trips, or the purchasing additional planes. Depending on the definition of units consumed, the marginal cost could just include the incremental cost of services for an additional passenger if the plane is already making a trip; the cost of fuel and labor if the marginal cost units consumed if the decision is whether a plane should be used for a particular route, or the entire cost of the plane as well as the cost of fuel and labor if the units of consumption are new planes. Computing the marginal cost of a pole used to distribute electricity, the marginal cost of a using a toll road or the marginal cost of a telephone call where virtually all costs are fixed is even more difficult. These examples are meant to demonstrate that applying the marginal cost formula to particular industries in order to understand future price trends is much more difficult than understanding the theory.

Much of the difficulty in computing marginal costs involves dealing with the time periods that are appropriate to use in measuring marginal cost. When computing marginal costs over a long time period, prices must cover the entire capital cost of buying new capital equipment, otherwise no new capital would be employed, demand would exceed supply and there would be never-ending shortages driven by insufficient capacity in a market. However over a short-time period, prices should correspond only to the incremental costs of producing one more item and in periods characterized by surplus supply of capital equipment capital costs are not part of the equation. This difference between short-run an long-run cost means that the presence of surplus capacity can have dramatic effects on price volatility, as prices may be reasonably stable when there is surplus capacity and suddenly change when the surplus goes away. Thinking about volatility from a marginal cost perspective means that if one uses historic data to predict future volatility, the errors can be dramatic. This also means that marginal cost calculations are complicated because they involve measuring variable cost of producing the product in the short-term when there is surplus capacity and then possibly adding something to variable costs to account for costs of building new capacity which must ultimately be a part of the price or the industry can never expand. It may be straightforward to calculate marginal costs in the short-run and also the marginal costs of adding new capacity which include costs of financing a new production facility. The problem still then remains as to how one should combine the two calculations and come up with some kind of way to put the short-term marginal costs and the long-term marginal costs together.

Understanding Short-term and Long-term Movements in Historic Prices

The starting point in evaluating key drivers in a valuation analysis is review of historic data, often involving a simple graph of the historic data (recall you can simply press the F11 key in excel after the data is set up with blank rows and columns in-between without a title for the x-axis.). Instead of computing volatility mean reversion or other statistics, it may be better to begin the analysis by asking basic questions about what are the underlying causes of the price trends and what could happen in the future. To be sure, simple extraction of historic trends in prices and other value drivers is one of the most dangerous mistakes that can be made in valuation as discussed in the case involving AES Drax from Chapter 1 where changes in the market structure drove dramatic changes in the level and volatility of prices. An example of reviewing historic prices is illustrated below for the case of the Baltic bulk index which measures prices

for transporting freight by ship. The volatility in prices is driven by fluctuations in the demand for materials to be shipped by freight. When making an investment in a ship that may last for thirty years or more, the one needs to understand both the near term outlook for prices, the potential range in prices and most importantly the long-term outlook. Prices are driven in large part by the demand for transport, but also by the time it takes to build new ships; the economics of scrapping ships; trends in productivity of building and operating new ships; and, the input prices such as the price of steel. These underlying drivers of supply include the capital cost associated with building new ships as well as the cost of operating existing ships. Capital costs include the cost of building new ships which are driven by changes in technology, the productivity of shipbuilding operations, the cost of steel, over-capacity of shipbuilding factories, the cost of capital and other things. Operating costs are determined by the price of oil, the price of labor and items such as the fuel efficiency of ships. The cost of capital, the price of energy, and technology improvement are similar to factors that drive the long-run marginal cost of many things. Predicting the magnitude and the length of cycles is very difficult if not impossible; understanding marginal costs that are the basis for equilibrium prices around which price cycles move can be a reasonable endeavor.

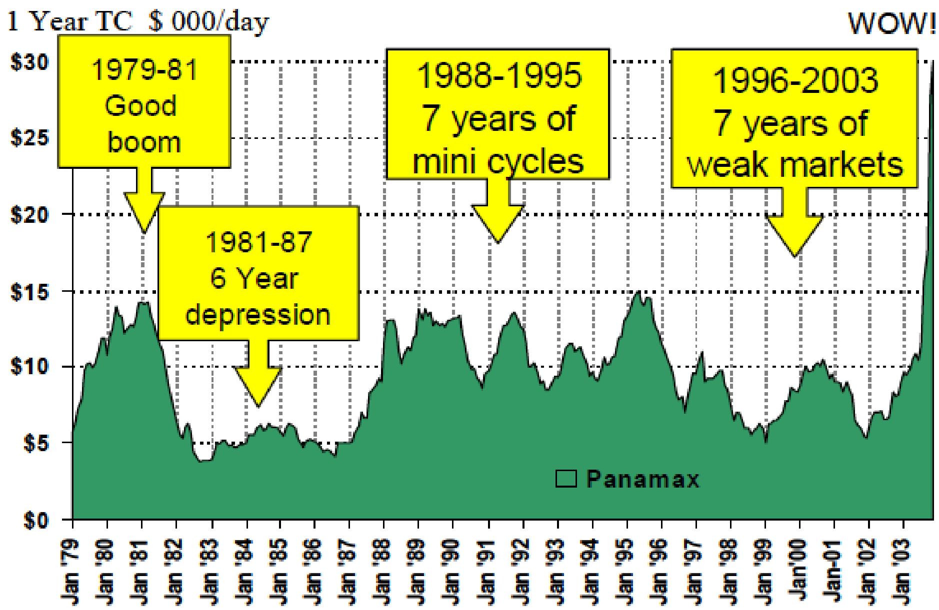


Figure 18 Dry bulk cycles 1996-2002 finally wore down investors' enthusiasm

The analytical discussion below uses the example of electricity pricing to illustrate various issues associated with development of supply and demand in the short and long run. While the pricing ideas can be easily applied to other markets, some characteristics of electricity are worthy of note. Four characteristics that drive determination of marginal cost, volatility of prices and ultimately valuation of generating assets are listed below.

(1) Like many other products, electricity cannot generally be stored, but rather must be currently produced to meet consumption with no ability for either consumers or suppliers to hold product in inventory so that they can hedge against unexpected changes in demand or supply. Without storage, the demand and supply curve are re-established in each period and there is no memory whereby surplus capacity from low demand in one period can offset high demands in subsequent periods and demand and supply are re-established for each short-term time period.

(2) Electricity demand fluctuates a lot from period to period. The demand level changes by large amounts between daytime and nighttime because of human activities; from day to

day because of changes in weather; and between different seasons because of space heating and air conditioning uses.

(3) In most electricity systems, the variable cost of production per unit varies significantly between low cost and high cost plants. Variation in the variable cost of production means that the supply curve has a steep shape (particularly when capacity comes close to its maximum level.) When demand reaches the high part of the supply curve, it is easy for producers to manipulate prices through holding back supply or refusing to generate unless prices reach extreme levels.

(4) In the vast majority of electricity markets around the world, the cost consumers incur when there are electricity shortages (i.e. the costs incurred by customers when their electricity is cut-off) is very high relative to the operating costs of producing electricity. In economic parlance, short-term price elasticity is low and demand response is small.

The fact that electricity cannot be stored drives many of the characteristics illustrated in Appendix One. For example, the mean-reversion of prices is caused by the fact that demand and supply curves are re-established in each time period; the fluctuation in demand results in differences between on-peak and off-peak prices; the cost of capacity shortages drives the extreme price prices; and the shape of the supply curve drives the very high volatility of short-term prices.

Computing Marginal Costs – Short-run Marginal Cost

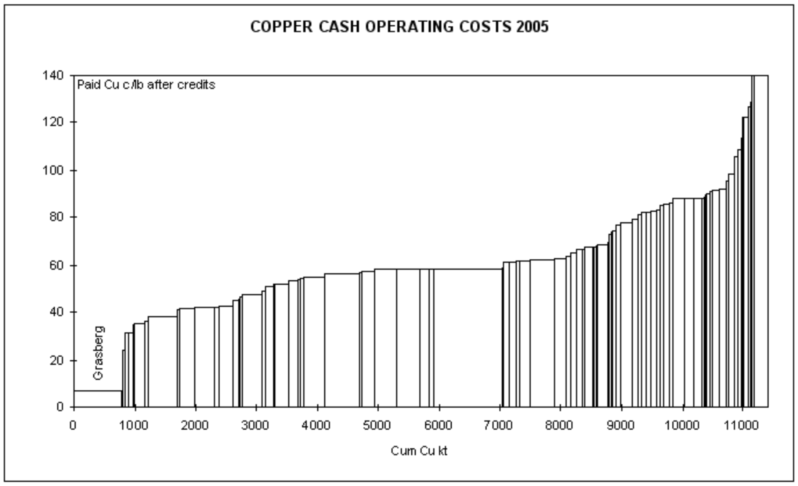
The remainder of this chapter delves into practical methods that can be used to compute short-run marginal cost, long-run marginal cost and integrating short-run cost together with long-run cost. As with other chapters, step by step modeling techniques are presented along with the theoretical discussion so that you can compute marginal costs in practice with exercises that walk through each part of the process. The first subject discussed is computing short-term marginal costs during times when there is surplus capacity through constructing a supply curve from variable cost. Subsequent sections address computation of marginal cost during periods when capacity is tight and the integration of long-term marginal cost with short-run marginal cost. In explaining how to compute marginal cost, electricity generation is often used to illustrate the mechanical techniques. While it may seem that the some of the modelling discussion is only relevant to electricity pricing, the idea of computing a supply curve to evaluate short-run marginal costs and the idea of evaluating capital costs of marginal new production can be applied across very many industries.

Short-Run Supply Curve

A supply curve plots the cost of supplying production on one axis relative to the amount of production over a certain period of time. In the short-run, the supply curve is represented by the variable production cost per unit, as producers will not choose to produce if the price is less than their cost. In virtually any industry there are a variety of different types of capacity produced in different regions (from plants with different ages, from plants that use different technologies, from plants that use different sources of supply) that can be used to make a product. To compute the short-run supply curve from capacity given the diversity of production in an industry, the costs of individual production plants must be gathered along with the capacity of each plant. Once the data is acquired for a given period of time, costs can be sorted and plotted against the cumulative amount of capacity. The figure below illustrates the supply curve for the copper industry.[3] In this case, the cost per unit is the net cost of producing copper (minus revenues received from production of gold and silver) divided by the production of copper. The bar with the lowest cost on the chart is for the Grasberg mine in Indonesia while mines with higher cost tend to be older mines located in the U.S. For the Grasberg mine, the size of the mine, the nature by which ore can be extracted, the labor costs and the significant amount of copper and silver at the mine drive the low cost

[3] This data can be found at www.minecost.com

per unit. In the case of each mine listed on the chart, the amount of production and the costs are computed over the course of a year. The graph shows that costs range from less than 10 cents per pound for the Grasberg mine in Indonesia to a high of 140 cents per pound. The x-axis shows that the world wide annual production of copper could reach 11,000 cubic kilotons (during the period of the late 1990's and the early 2000's, some expensive capacity was shut down because there was more than enough capacity to produce all of the required copper from other mines.) As such, the supply curve in this case illustrates the amount of capacity just required to meet demand.



Modeling the Supply Curve for One Period

To create a supply curve graph such as the one shown above, the electricity industry is used as an example. Because electricity cannot be stored, the time period for measuring production is the instantaneous amount of capacity that can be produced at a given period of time, rather than the amount of capacity that can be produced over the course of a year. This also means that supply which is uneconomic in a particular hour cannot practically be taken out of the supply curve as is the case for copper. To construct a supply curve for electricity, the first step is calculating variable cost of running each unit in a market and the second step is sorting the list of plants according to the variable cost. Once the plants are arranged in the order of their operating cost, the capacity associated with each plant is accumulated according to the sorted variable cost. In creating the supply curve, a couple of programming techniques that can be helpful:

1. Collect capacity and the cost of each plant or each unit. This is often publicly available from sources such as the Energy Information agency and independent system operator websites. The example below uses bid data from the PJM website where the amount of capacity and the bids for each increment of capacity are listed (the bid price is used to represent variable cost.) In arranging the costs and capacities of the plants, provisions should be made for being able to add new plants, remove plants permanently or temporarily and to change the cost of operating the plant as factors such as fuel prices change.

2. Once the data for costs and capacities is acquired, the data set must be sorted according to the variable cost (or bid price). Rather than using the simple sort function in excel, it is useful use an alternative method which maintains the original list of data so that the data does not have to be re-sorted each time the characteristics of the plants change. This can be accomplished by creating a numeric tabulation of the plants in a separate column and then using the SMALL function. The SMALL function requires an array of data – in this case the cost per unit – along with a counter. When the counter is 1, the smallest value is produced. Once the SMALL function is used to arrange the variable cost of each unit, the capacity can be matched with the cost through using the INDEX and the MATCH command together. The MATCH command is first applied, where the individual sorted cost is matched against the sorted column of costs to establish the ranking

number for each plant. Once this ranking is established, the INDEX command can be used to find the name of the plant and the capacity of the plant.

3. In order to make the above process work when there are multiple plants that have the same variable cost, a very small random number can be added to the variable cost in an additional column. This column rather than the variable cost without the random number should be used with the SMALL function. To add a very small random number, the following formula could be used:

   Adjusted Variable Cost/MWH = Variable Cost/MWH + RAND() x .0000000001

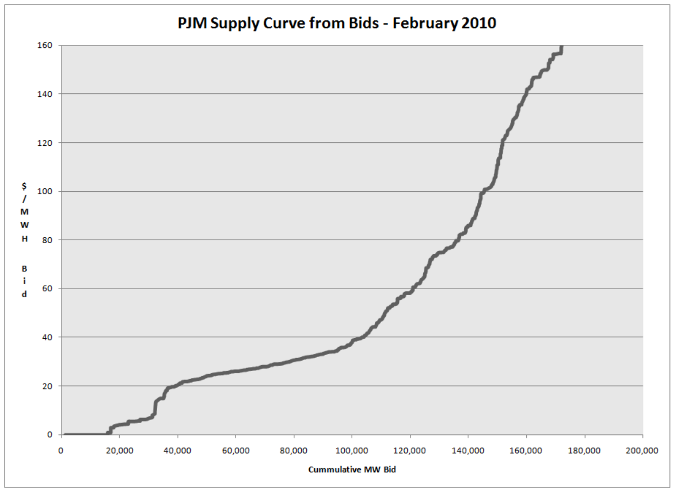
4. With the capacity column that is sorted along with the variable cost developed using the MATCH and INDEX commands above, accumulate the capacity by summing the prior balance with the next increment of capacity. The accumulated capacity is the x-axis of the supply curve while the sorted variable cost per MWH is the y-axis data that is plotted.

5. Create the supply curve graph diagram by using the F11 key, where the accumulated capacity is in a column to the right of the sorted variable cost. To make the accumulated capacity the x-axis, do not include a title on this column (or at least leave a blank space above the numbers.) After pressing the F11 key, the graph will not look like a supply curve until you change the type to an x/y graph.

An example of this process is shown in the table and the graph below for the PJM electricity market in the U.S.[4] PJM publishes bids and the associated capacity which are re-formatted on the left-hand-side of the table. The manner in which the data is converted to a sorted supply curve using the SMALL, MATCH and INDEX function is shown on the right-hand-side of the table.

Raw Data				Sorted Data for Supply Curve				
Row Code for Plant	Column Code for Unit	MW of Capacity Unit	Bid in Terms of $/MWH for Unit	Bid in Terms of $/MWH for Unit with RAND	Counter for Plant	Sorted Cost from SMALL Function ($/MWH)	Row Number of capacity from MATCH Function	MW of Capacity from using INDEX function
885	10	0	-	0.00	8850	33.72	7933	50
886	1	100	20.28	20.28	8851	33.72	8932	20
886	2	25	32.75	32.75	8852	33.77	5618	7
886	3	50	33.20	33.20	8853	33.79	3730	8.7
886	4	50	35.51	35.51	8854	33.79	5601	80
886	5	30	40.62	40.62	8855	33.80	5602	40
886	6	33	44.75	44.75	8856	33.83	5901	185
886	7	0	-	0.00	8857	33.89	10483	8.9
886	8	0	-	0.00	8858	33.89	6598	25
886	9	0	-	0.00	8859	33.91	8734	40
886	10	0	-	0.00	8860	33.92	4274	42
887	1	165	4.58	4.58	8861	33.93	6599	5
887	2	85	20.33	20.33	8862	33.95	7883	50
887	3	75	23.18	23.18	8863	33.98	4275	1
887	4	50	23.46	23.46	8864	34.01	7654	100
887	5	50	23.74	23.74	8865	34.01	7634	89

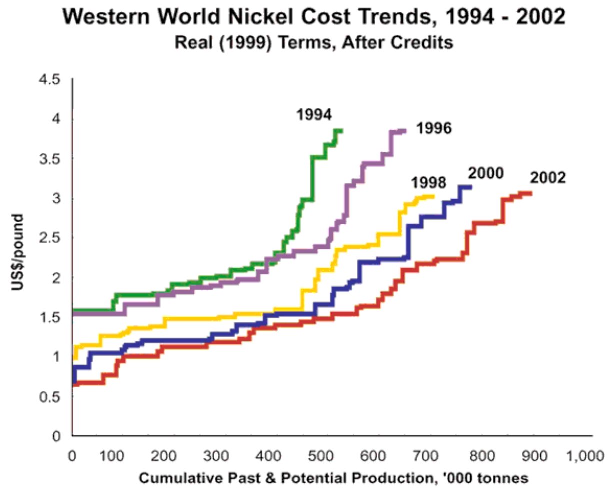
[4] Data for the bid of each increment of capacity is published on the website www.PJM.com. Similar supply curve data can be found on other Integrated System Operator (ISO) websites.



For electricity, the left most points of a supply curve are generally run-of-river hydro and nuclear plants – plants that have very low variable operating costs (low fuel costs). Subsequent capacity on the x-axis may include coal plants, combined cycle units and peaking plants. The plants with relatively high costs may be units that have a high fuel price such as old diesel plants operating on fuel oil or they may be plants that have low efficiency such as simple cycle turbine plants. The variable cost on the y-axis is driven by the fuel cost and the efficiency of each plant. Efficiency is measured by the heat rate -- BTU energy input relative to electricity output – where lower efficiency plants have a higher heat rate. Sorting capacity according to variable cost and accumulating capacity defines the supply curve because it depicts the price level at which managers of generating units will in theory offer to supply their power.

In terms of suppliers, if the price was different than the variable cost of the most expensive unit (or the variable cost of the next most expensive unit that is not running), then there would be excess or deficient supply in the market. Consider first the situation in which the price is lower than the cost of the most expensive unit that is necessary to meet demand. then the operator of the relatively high variable cost generating unit that is needed to meet demand will not run his plant and the market demand will not be met. On the other hand, if the price is above the cost of the marginal unit that just meets demand, plant owners with variable costs above the cost of the last unit will attempt to provide supply to the market. In this case too many suppliers will try to run their plants and there will be excess supply. Only when the price is equal to the cost of the last generating unit, is the appropriate amount of electricity supplied to the market.

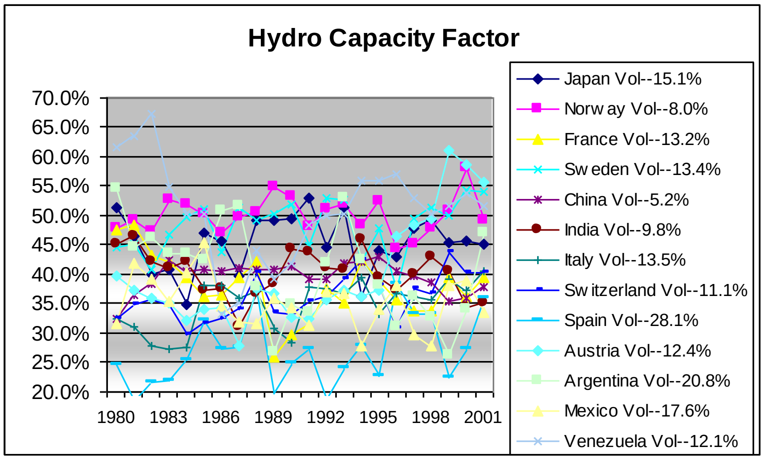
The shape of the supply curve determines the level of marginal costs in an hour as well as the volatility of prices and costs. If the supply curve was a 45 degree line, then changes in required supply to meet demand would be proportional to changes in marginal cost. If the supply curve was a straight horizontal line implying no diversity in supply, then changes in required supply would have no effect on price. If there are new supply additions in a market, or changes in the capacity of existing plants, or changes in factors that drive the variable cost, or changes in a host of other factors, the supply curve can shift – shifts to the left or right and/or movements downward and upward. If the level of demand that drives the required supply is known and not sensitive to price, then the changes in price over time could be analyzed through movements in the supply curve. The shape of the supply curve as well as changes in its shape is crucial elements in understanding trends and the volatility of prices. This means that changes in price are driven in part by changes in the shape of the supply curve over time as new capacity is added and old capacity is removed, as input costs such as energy and food change, as capacity is out of service for maintenance and as the productivity of new and existing resources change. The graph below illustrates differences in supply curves for Nickel over a six year time period. The supply curve for 2002 includes a lot of new capacity relative to the supply curve for 1994. The maximum production in 1004 was around 500,000 tons while the capacity in 2002 increased to 900,000 tones. If the annual demand for nickel was 400,000 in both 1994 and 2002, then in theory the price should have declined from about 3 to about 1.5 (this is gauged by drawing a vertical line on that chart at the 400,000 level.)



In the case of electricity, the shape of the supply curve will change if hydro production falls, if the fuel prices change, if plants are not available because of maintenance and other factors. The effects of changes in the supply curve can be demonstrated by returning to the case of the California power crisis discussed in Chapter 1. A reduction in hydro generation, increase in natural gas prices (that were influenced by market manipulation of a gas supplier), outages of many generating units (again probably influenced by market manipulation) and increases in the cost of buying emission credits mean that the supply curve shifted to the left and also shifted upwards. Given a level of demand, the expected changes in price from these factors can be evaluated. If a plant cannot be operated because it is out of service for maintenance, its capacity should not be included on the x-axis of the supply curve and the unit with the highest variable cost to meet a given level of demand changes. Finally, if a new plant is added in the market, this capacity should be included in the arrangement of costs and capacity that is used to construct the curve.

Simulating Variability in the Supply Curve

To project both the level and the volatility of prices, potential movements in the supply curve should be considered in the short-term and in the long-term. If one is projecting trends in the supply curve, the techniques developed described in Chapter 3 to model the volatility of prices can easily be applied to construct simulated volatility of marginal costs. For example, consider the variability in hydro production. The graph below illustrates the volatility of hydro generation for different countries in the graph below which demonstrates the that hydro production can vary by a wide margin from year to year. Trends in hydro production around the world clearly are mean reverting and the volatility varies between 8% for Norway and 28% for Spain. As with any time series, the volatility of hydro production can be measured from historic data.



To incorporate hydro volatility into a supply curve, one could multiply the mean level of hydro energy in the supply curve by the historic standard deviation of hydro variation and by the inverse of the standard normal distribution of a random variable (assuming that the variation in hydro production is normally distributed) using the following equation:

Hydro Capacity = Base Hydro Capacity x NORMSINV(RAND()) x Volatility

Similar techniques can be used to simulate plant outages, volatility in fuel costs, changes in new capacity and other factors that drive the supply curve. To compute plant outages, one can use historic data for outage percentages and determine the probability that a particular plant will not be operational on a given day (known as forced outage). Given the probability, a simulation analysis can be created to reflect the possibility that any particular plant will not be available. The mechanics of representing changes in the supply curve through simulation of outages, hydro volatility, fuel price variability and changes in capacity can be accomplished using the following process:

1. For non-hydro thermal units, you can create a SWITCH variable to define whether a unit is available along with a variable that records the outage rates and a variable that records the fuel cost index next to the list of capacity. For the hydro units include another SWITCH variable that identifies whether the unit is a hydro unit and another variable for volatility adjustment.

2. To model outages, you can use the RAND() function in excel that creates a variable between zero and one. If the RAND() result is below the outage rate, then the SWITCH is set to FALSE and the capacity is set to zero. If, on the other hand, the RAND() function is above the outage rate, then the SWITCH is set to TRUE and the full amount of the capacity is assumed to be available. Recall, that an IF statement is not necessary to accomplish this. Rather, you can simply use a logical statement as follows:

   Outage Switch = RAND() > Outage Rate

3. In modeling the volatility for fuel prices and hydro capacity the RAND() function can be used to simulate how different variables affect movements in the supply curve using time series analysis. To do this, the volatility parameter should first be developed which can depend on the period being modeled (Chapter 3). For example, in the case of natural gas prices, the index will be different as one proceeds further into the future. The volatility factor can then be matched with the period of the supply curve and the capacity or the fuel cost can be adjusted. If a series of different fuel costs are being modeled, they can be modeled in an integrated manner using the Cholesky factors described in chapter 3.

After establishing a supply curve with stochastic elements, the future level and the variability of the supply curve can be simulated. Depending on the shape of the supply curve and the amount of surplus capacity in a region, the effects of variations in the supply curve may have a large effect on prices or a relatively small impact. From a practical perspective, thinking about the supply curve and the variability in factors that drive levels of capacity and the price of inputs can affect valuation analysis.

Short-Run Demand Curve

Given that prices are determined by the intersection of the supply and demand, this section combines the discussion of the supply curve with various issues associated with measuring demand. The discussion considers demand changes in short periods when the quantity of supply is fixed in the market (i.e. without considering constructing new capacity). Modeling price behavior from movements in demand that are not affected by changes in price (without price elasticity) is first considered. Next, the issue of incorporating demand elasticity is described from the standpoint of modeling changes in price. The final part of this section describes overlaying a demand curve with the supply curve in order to simulate prices. To illustrate the mechanical process of price derivation when demand changes in the short-run, the case of electricity introduced above is continued. This example is convenient because electricity cannot be stored in inventory (electricity is not all that unique since no product can be stored indefinitely in inventory because of storage cost) and changes in demand have a direct effect on price. Modeling for many other industries is similar (one cannot easily store airplane passengers, broadband, road traffic, health club usage, theater performances and many other products.) In modeling analyzing products that can be stored in inventory, the analysis may be for a month or a year rather than an hour, but many of the principles will be the same.

The idea that the clearing price must be the variable cost of the most expensive unit running can be demonstrated by considering the perspective of both suppliers. When discussing the supply curve from the standpoint of producers, it was demonstrated that the only price that clears the market is the cost of operating the most expensive plant that is necessary to meet supply. From a consumer perspective, the amount of economic resources (fuel and cost of operating and maintaining plants) that change when usage is slightly changed is also driven by the cost of the most expensive plant running or the marginal unit. The equation below demonstrates this notion:

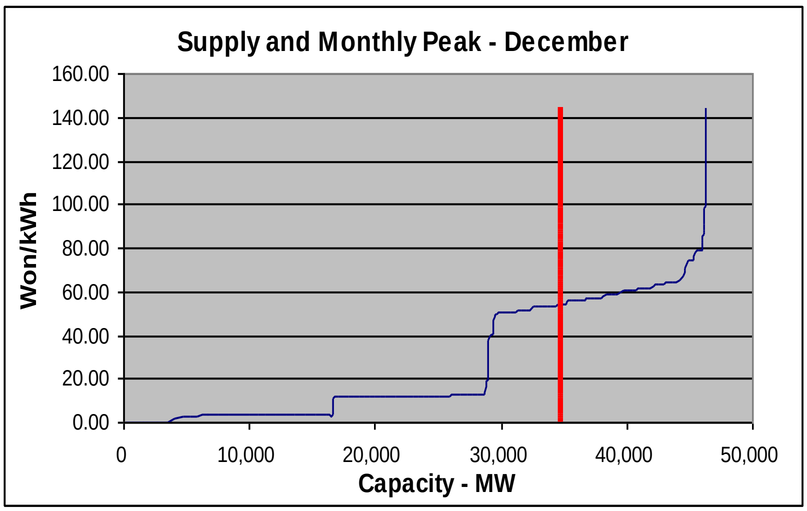
Change in Economic Resources = Cost of Most Expensive Unit Running x Change in Usage

If the demand does not change much with different levels of price – i.e. it is completely inelastic – then equating supply with demand can be accomplished by simply finding the plant with the variable cost that just meets the given level of demand or the variable cost of the most expensive capacity increment unit that is currently operating in the market. This level of production with the highest variable cost is the increment of capacity that will operate somewhat more or somewhat less if there is a small increase or decrease in demand. If anyone in the market changes their usage slightly, all of the plants except the plant with the highest variable cost will not change the way they operate. In the case of electricity, it is the plant that is the most expensive to operate that will increase or decrease its usage when somebody switches on or off a light bulb.

A basic proposition of microeconomics is that demand for a product is responsive to price meaning that the demand curve slopes downward as consumers desire less of a good when the price is higher. When analyzing the pricing in short time periods during which there is sufficient capacity to meet the level of demand, it is reasonable to presume that the demand is quite insensitive to price. In the case of electricity, businesses and homeowners will probably not significantly change their level of usage in the short-run if the price level in wholesale markets is $22/MWH rather than $27/MWH (2.2 – 2.7 cents per kWh.) On the other hand, the level of electricity demand probably varies significantly with different weather conditions and different states of the economy. In economic parlance, the demand curve is inelastic and on a graph of quantity versus price, the demand is a vertical line. This means that once we know the weather, the time of day, the season and the level of economic activity, the demand can be computed in a fairly accurate manner. The assumption that demand is inelastic means that the observed

actual demands in the market do not have to be adjusted if there is a change in price (one often assumes that demand changes because of economic growth, the weather or other factors, but one does not have to adjust demand for every hour that price changes).

The graph below illustrates the process of price determination where demand is inelastic and sufficient capacity is available in the market. After the level of demand in a particular period is established, that amount can be drawn as a straight line on the supply curve to determine the price. In the case of electricity, the price is simply the variable cost MWH at the point where supply equals demand. Changes in price from one period to the next can be driven either by the changes in the demand level or by shifts in the supply curve. Here, when the vertical line moves because of a different level of demand, the price changes according to the location of the vertical line. The effects of changes in demand on the price depend on the shape of the supply curve. If the supply curve were flat, then changes in demand do not affect price. If the supply curve had a 45 degree line, changes in price vary in proportion to changes in demand. If the supply cure is steeper than 45 degrees, change in price is more than the percent change in price. In this case price depends on the ability of some suppliers to remove their capacity from the market. In other situations where storage is possible, the capacity removed from the market may occur through mothballing capacity.



From a mechanical standpoint, computation of the market clearing price is straightforward if the demand is a vertical line without price elasticity and there is sufficient capacity to meet the fixed demand. After arranging the level of demand in a row or a column, the following steps can be used to determine the market clearing price:

1. Use the MATCH function and find the row or column number for which the given demand equals the series of sorted cumulative capacity from the supply curve discussed above.

2. The process above must be adjusted because the MATCH command will give the lower number that just matches the capacity. For example, if the demand is 1,200 and the first accumulated capacity increment is 1,000 while the second is 1,500. In this case the match command yields the number 1 for the smaller number of 1,000. However, for marginal cost, you need the higher number because the second plant must be running to meet demand. Therefore, you should add one to the MATCH function.

3. In the above example, if the demand is exactly 1,000, you would like the MATCH function to yield 1 which was the number before the adjustment instead of 2. To make this adjustment, you can reduce the demand by a small increment as illustrated in the equation below:

MATCH(Demand - .5, Accumulated Sorted Capacity) + 1

4. After finding the row number in the supply curve by using the adjusted MATCH function, you can use this row number in the INDEX function to find the clearing price, where the INDEX looks at the sorted variable costs associated with the row number from above.

Simulation of Price Levels and Price Volatility without Capacity Constraints

This section shows that for a given level of demand variation how variability in alternative parameters affect the price variability. To illustrate how the supply curve can affect volatility, two scenarios are applied. The first scenario assumes that a lot of surplus capacity exists while the second assumes capacity is near demand. Capacity added is assumed to be low cost capacity near the bottom of the supply curve. The system is assumed to have 30% hydro that has a volatility of 15% on an annual basis. Natural gas prices are assumed to have a volatility of 25% and plants are assumed to have an outage rate of 5%. Given the same level of demands, the graph on the right presents a series of simulations over the course of a year with no capacity additions while the graph on the left presents the same data with low capacity additions. The graphs demonstrate that changes in the structure of a market affect both the level and the volatility of prices.

The practical implication of this analysis from the standpoint of general financial modeling is to see that one can make a relatively simple forecast of a market by knowing the supply and demand and that both the level and the volatility are affected by capacity additions. If a lot of capacity is being added to a market, the volatility will not be the same as when capacity is constrained.

Price Elasticity and Demand Response with Constrained Capacity

The example above made two crucial assumptions that affect both the level and the volatility of prices. The first assumption is that demand is not at all responsive to price and the second is that the level of fixed demand remains below the total capacity in the market. In this section these assumptions are relaxed and pricing mechanisms are evaluated in situations where total capacity in a market is deployed and the market is cleared through demand responses to price. Demand response is analyzed through explicitly incorporating alternative demand elasticity parameters into the demand curve and supply constraints are modeled by a vertical line at the right of the supply curve.

The issue of demand elasticity and supply constraints has many policy implications in addition to the analytical issues. Without demand responsiveness to price, the whole idea of marginal cost pricing would not have much meaning in terms of economic efficiency. This is because under the assumption of perfectly inelastic demand, when prices change, the level of production in the economy does not change. If demand is a straight line, then the quantity produced in the market will be defined by that line (unless there are shortages) and a market clearing price mechanism (as opposed to regulated prices) does not change the market supply. Alfred Kahn discusses this idea that the behavior of business and individuals drives prices to marginal cost[5]:

> *But why does economic efficiency require prices to equal marginal, instead of, for example, average total costs? The reason is that demand for all goods and services is in some degree, at some point, responsive to price. Then, if consumers are to decide intelligently whether to take somewhat more or somewhat less of any particular item, the price they have to pay for it (and the prices of all other goods and services with which they compare it) must reflect the cost of supplying somewhat more or somewhat less -- in short, marginal opportunity costs.*

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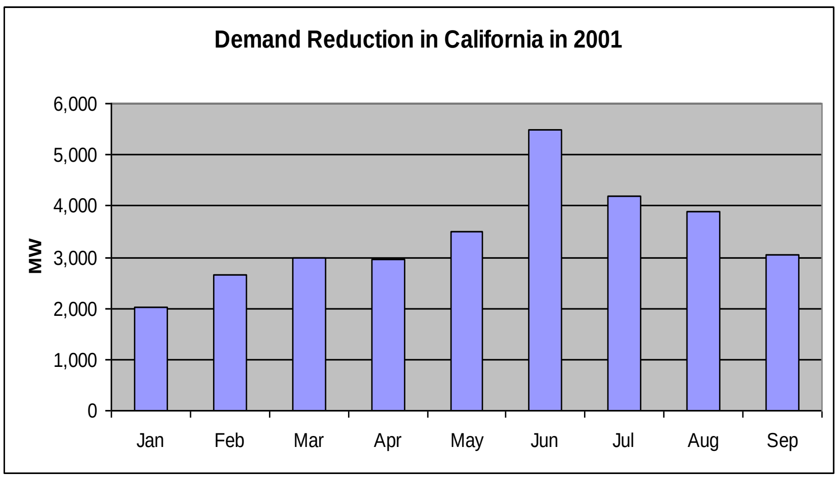
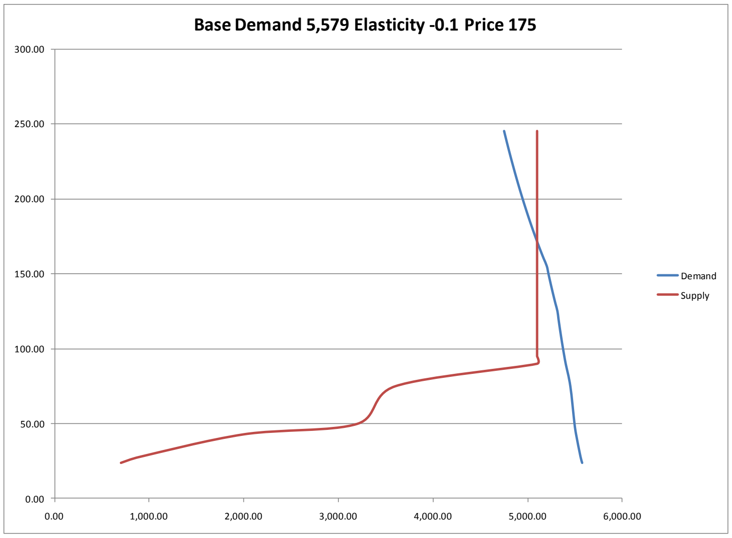
[5] Kahn, Alfred P. “The Economics of Regulation, Volume One.”

Because of the idea that demand elasticity is a driver of economic efficiency, the amount of electricity reduction that comes about from changes in price is an important factor in establishing competitive market systems. In one assumes that consumers do not change their usage when prices change, then the level of price established from a competitive market does not affect economic efficiency in terms of the manner in which plants are operated. For example, if a system establishes prices to suppliers but not to consumers (this is the case for a single buyer market), the operation of power plants is not affected by changes in demand that respond to price changes. The demand response to price has been the subject of lively debate in explaining the California crisis and in policy arguments involving the benefits of deregulation. In particular, some advocates of a market system suggested that since the market system in California did not de-regulate prices at the retail level for most customers and most customers did not see the very high de-regulated wholesale prices in their electric bills, demand was kept artificially high. The suggestion is that the crisis would have been far less costly if the market system had allowed customers to see prices which would have induced reductions in demand because of price elasticity. Others argue that electricity has small elasticity in the short-run at any price and demand response has not been caused major shifts in demand in any de-regulated market. The amount of demand reduction that the California Energy Commission estimated is shown in the graph below.[6]



From an analytical perspective, the question is how to establish prices when demand driven by non-price factors such as weather and economic activity is high relative to the total capacity in a market. This was the case for goods like copper, steel, container ships and many other things before the financial crisis as demand from China and other countries was putting pressure on the amount of available capacity in the market. To model prices in these circumstances, a few adjustments are necessary. First, the supply curve is modeled as a vertical line when the capacity limit is reached. This means that supply is perfectly inelastic as no matter what the price, the total amount of production cannot be increased. Second, since the supply curve is a straight line, if the demand curve is also a straight line to the right of the supply curve, then supply will not equal demand and shortages will occur. Without constraints on prices from regulatory or other mechanisms, prices could attain high enough levels such that demand would cease to be a straight line but instead would slope downward until price matches the vertical level of supply. Third, as the slope of the supply curve is not constant across different levels of production, so to the demand elasticity should not be the same for different levels of demand. Market clearing prices with supply constraints and demand elasticity using these ideas are illustrated on the graph below:

[6] Source: California Energy Commission.



The mechanics of establishing a graph like the one above involve the following the following steps in addition to the method discussed above:

1. The supply curve must be adjusted so that it becomes a straight line when the limit of total capacity is reached.
2. Demand elasticity must be incorporated into the demand curve so that it has a downward slope.
3. The resolution of prices is computed by finding the point at which surplus demand or surplus supply is zero rather than matching the demand to the cumulative capacity.

Mechanical issues in resolving the supply and demand when supply is constrained are presented below. In describing how prices can be resolved in periods of constrained capacity it is not argued that this system is somehow idea and leads to economically efficient outcomes. Because prices increase dramatically when demand must be reduced to clear the market, the profit of suppliers can increase just as radically. Needless to say, suppliers like the price spikes and will attempt to do things that make the market reach conditions of constrained supply. Where active competition, strong demand response and the potential for storage is in place, the problem is less severe. However if a bidding system for electricity is implemented, games can be played and capacity can be withheld which prompts very high prices and high profits for suppliers. This occurred with Enron and other suppliers in the California power market during the crisis of 2000-2001. Theorists who believe that markets can operate efficiently assert that price elasticity can moderate the effects of price spikes when capacity is constrained. A major issue surrounding the question of whether electricity markets can operate efficiently without some kind of government intervention is whether demand response to price signals can be meaningful when capacity is constrained. If demand is sensitive to price in the short-term, price volatility will be less and it will be more difficult for suppliers to manipulate the market.

Computing the Supply Curve with Capacity Constraints

To compute the supply curve with capacity constraints one can extend the supply on a vertical basis once the maximum capacity has been reached. This represents the fact that no more supply can be offered than the maximum capacity and that when the maximum capacity is reached, consumers can bid higher and higher prices in order to be in the group that can be supplied. The mechanics of computing the supply curve in this situation is to add prices above the maximum cost of production and assume that the maximum production could be offered at a range of the different prices. Mechanically, this involves the following steps:

Step 1: Establish a price increment (e.g. US$5/MWH)

Step 2:Create a TRUE/FALSE switch variable that distinguishes rows with available capacity for a number of rows after the highest available capacity.

Step 3: When the switch variable is TRUE, increment the cost by the price increment, otherwise use the price from the supply curve analysis.

The basic supply curve and the extended supply curve are illustrated in the table below:

Base Supply		Extended Supply		
Cummul Capacity After Sort	Marginal Cost of Prod	Sufficient Capacity Switch	Extended Supply	Extended Prices
700	24.00	TRUE	700.00	24.00
900	28.00	TRUE	900.00	28.00
2000	43.00	TRUE	2,000.00	43.00
3200	50.00	TRUE	3,200.00	50.00
3600	75.00	TRUE	3,600.00	75.00
5100	90.00	TRUE	5,100.00	90.00
		FALSE	5,100.00	95.00
		FALSE	5,100.00	100.00
		FALSE	5,100.00	105.00
		FALSE	5,100.00	110.00
		FALSE	5,100.00	115.00
		FALSE	5,100.00	120.00
		FALSE	5,100.00	125.00
		FALSE	5,100.00	130.00
		FALSE	5,100.00	135.00
		FALSE	5,100.00	140.00

Computing Price Elasticity of Demand in the Short-term

Price elasticity is defined as the percent change in quantity divided by the percent change in price. The long-term price elasticity is often measured in regression analysis where the quantity demanded in an industry is related to income and other factors as well as price. If the demand and price data are expressed in logarithmic form, the price elasticity can be plopped out of the equation as illustrated below:

$$\text{Log(Demand)} = A + B \times \text{Log(Income)} + \text{Price Elasticity} \times \text{Log(Price)}$$

The price elasticity required for modeling demand in the short-term is very different than that computed from demand equations analogous to the one shown above. When reacting to price changes in the short-run it may be difficult to find information, change capital equipment, or even modify basic behavior such as switching off lights. Modeling of demand response requires estimation of price elasticity during short-term periods sometimes when prices are much higher than usual. The assumption that price elasticity is the same during low price periods and high price periods may not be reasonable. While attempts have been made to estimate the elasticity and the cost to consumers of outages has been measured, the notion that a price elasticity parameter for constrained periods when prices are high can easily be computed from historic data is probably fantasy. Needless to say, computing the demand curve with price elasticity is more difficult than establishing the supply curve (assuming data is available.)

Even if estimates of price elasticity are not precise, the process of modeling demand that result from alternative elasticity parameters can be an instructive exercise. To see how this process works, begin

with the definition of price elasticity, which is the change in price divided by the change in quantity (when computing price elasticity it is better to use the LN function than to use discrete percent changes.) In logarithmic form, the formula for elasticity is:

$$\text{Elasticity} = \text{Ln}(Q_1/Q_0)/\text{Ln}(P_1/P_0)$$

If the LN function is applied rather than expressing elasticity in discrete percent changes (e.g. Pct Chg = (Q_1/Q_0)-1) the elasticity does not depend on the order in which the data is arranged as $\text{Ln}(P_1/P_0) = -\text{Ln}(P_0/P_1)$. The idea that use of logs results in more stable elasticity calculations is illustrated in the table below. After presenting a series of quantities and prices, the first block computes price elasticity using discrete percent changes where the percent change is from the previous price (e.g. (100/91.29-1)/(10/12)-1)) while the second block uses the current value divided by the next value. Note that where the discrete formula is used the elasticity is not constant and that different values are obtained depending on the starting point of the formula. Using logs avoids the problem.

		Discrete Pct from Prior Value			Discrete Pct from Next Value			Use of LN		
Q	P	Pct Chg Q	Pct Chg P	Elasticity	Pct Chg Q	Pct Chg P	Elasticity	Pct Chg Q	Pct Chg P	Elasticity
100.00	10				0.10	-0.17	-0.57	(0.09)	0.18	-0.5
91.29	12	-8.7%	20.0%	-0.44	0.08	-0.14	-0.56	(0.08)	0.15	-0.5
84.52	14	-7.4%	16.7%	-0.45	0.07	-0.13	-0.55	(0.07)	0.13	-0.5
79.06	16	-6.5%	14.3%	-0.45	0.06	-0.11	-0.55	(0.06)	0.12	-0.5

To implement the formula in a supply and demand analysis to derive prices, the following steps can be used:

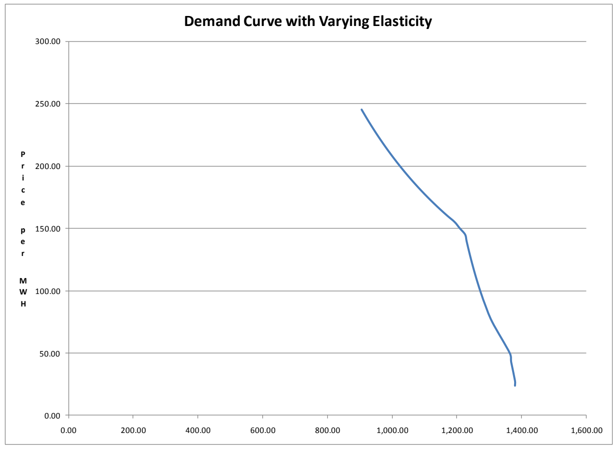
1. Establish a base demand. This level of demand is the theoretical demand if the price would be very low and it may be very difficult to establish. However, the goal seek function can be used to find the level consistent with moderate levels of observed demand.

2. Compute the level of demand for the all of the production costs including the outage costs defined above using the formula:

   $$\text{Demand} = \text{EXP}(\text{Ln}(P/P_0) \times \text{Elasticity}) * \text{Demand}_0$$

   Where P is the price associated with the level of production. The equation comes from re-arranging the elasticity equation above.

3. To implement elasticity in analysis of marginal costs, one can assume the elasticity is zero or very low when there is sufficient capacity to meet demand and then assume that elasticity comes into play when prices increase. A demand curve with increasing elasticity is illustrated below:



Computing Market Prices with Price Elasticity of Demand in the Short-term

The final step is to compute prices that can be established either from situations where adequate capacity exists or from situations in which the capacity is constrained and prices are established from the vertical portion of the supply curve along with the demand curve. To accomplish this, one can simply make a calculation of the surplus demand (the total demand less the accumulated capacity) at each price. Once the surplus demand is computed, the level at which it reaches zero is the clearing price. Since prices are computed in increments and the surplus demand will be highest when the production cost and the accumulated capacity is low, the level of surplus demand will gradually decline until it becomes a negative number. In general, because increments of price are chosen, there will be no point at which the surplus demand is exactly zero. Instead, the MATCH function can be used with a switch of -1 at the end. The -1 switch named greater than in excel will find the row number at which the surplus demand remains positive. The market clearing price should be where the supply exceeds demand by a small amount and therefore it should be the row subsequent to the row found by the match statement. Finally, once the supply is established, the market clearing price can be found through using the INDEX function where the array of prices are used together with the row number from the MATCH function.

An illustration of market clearing prices that include both periods where supply is constrained and where surplus capacity is available is presented in the table below. Note that demand declines from increases in price and the surplus demand keeps falling and eventually becomes negative. The market clearing price is the level where the first negative surplus demand occurs.

Match Row	15
Clearing Price	135

Base Supply		Extended Supply					
Cummul Capacity After Sort	Marginal Cost of Prod	Sufficient Capacity Switch	Extended Supply	Extended Prices	Elasticity	Demand Curve	Surplus Demand
700	24.00	TRUE	700.00	24.00	0.00	5,679.00	4,979.00
900	28.00	TRUE	900.00	28.00	0.00	5,679.00	4,779.00
2000	43.00	TRUE	2,000.00	43.00	-0.02	5,630.48	3,630.48
3200	50.00	TRUE	3,200.00	50.00	-0.02	5,613.52	2,413.52
3600	75.00	TRUE	3,600.00	75.00	-0.10	5,390.47	1,790.47
5100	90.00	TRUE	5,100.00	90.00	-0.10	5,293.08	193.08
		FALSE	5,100.00	95.00	-0.10	5,264.54	164.54
		FALSE	5,100.00	100.00	-0.10	5,237.60	137.60
		FALSE	5,100.00	105.00	-0.10	5,212.11	112.11
		FALSE	5,100.00	110.00	-0.10	5,187.92	87.92
		FALSE	5,100.00	115.00	-0.10	5,164.91	64.91
		FALSE	5,100.00	120.00	-0.10	5,142.98	42.98
		FALSE	5,100.00	125.00	-0.10	5,122.02	22.02
		FALSE	5,100.00	130.00	-0.10	5,101.97	1.97
		FALSE	5,100.00	135.00	-0.10	5,082.76	-17.24
		FALSE	5,100.00	140.00	-0.10	5,064.30	-35.70
		FALSE	5,100.00	145.00	-0.10	5,046.56	-53.44
		FALSE	5,100.00	150.00	-0.40	4,978.59	-121.41
		FALSE	5,100.00	155.00	-0.40	4,913.72	-186.28
		FALSE	5,100.00	160.00	-0.60	4,821.00	-279.00
		FALSE	5,100.00	165.00	-0.60	4,732.81	-367.19
		FALSE	5,100.00	170.00	-0.60	4,648.79	-451.21
		FALSE	5,100.00	175.00	-0.60	4,568.64	-531.36
		FALSE	5,100.00	180.00	-0.60	4,492.06	-607.94
		FALSE	5,100.00	185.00	-0.60	4,418.82	-681.18
		FALSE	5,100.00	190.00	-0.60	4,348.68	-751.32
		FALSE	5,100.00	195.00	-0.60	4,281.43	-818.57

Market clearing prices resulting from demand curves with alternative price characteristics are illustrated on the graph below assuming the same supply curve. When capacity is constrained, the graph demonstrates that estimates of the price elasticity of demand become the driving force behind the difference in market clearing prices. Prices increase from about 125 to about 200 if the demand elasticity is reduced. From an analytical perspective this is unfortunate because of the difficulty in estimating price elasticity and the lack of data during times when capacity is constrained in a market. To derive price elasticity one would have to first know periods during which capacity is constrained. Next, one would have to determine other points on the demand curve and make a computation of the elasticity. On the other hand, when production is not constrained and demand is inelastic, the supply curve is the primary determinant of the price.

Practical Issues and Implications for Financial Models

Understanding the theoretical process for determining prices may be interesting, but the question remains how to apply models such as those described above in practical financial analyses and valuation. In the real world it is difficult to gather cost data on an entire market and it is even more challenging to make estimates of the price elasticity of demand. However, even if a comprehensive market model is not created because of time and/or data constraints, the general theory can be quite useful in understanding of the potential for prices to increase suddenly when capacity is constrained and decrease for protracted periods when surplus capacity exists in a market. The general principles of understanding the shape of the supply curve, the level of surplus capacity in a market, demand responsiveness to price changes and prospective supply additions in the market can have dramatic effects on price and quantity assumptions that drive financial models. This type of analysis can apply to ports, airplanes, hotel rooms, copper prices, oil rigs container ships and many other things. The analysis should make the danger of assuming a trend line derived from historic levels of prices obvious in situations where there is a risk of surplus or deficient capacity. In forecasting costs and margins, the danger is forecasting that low input costs which were present when surplus capacity exists will continue into the future.

The shape and risk distribution of the supply curve will be further discussed later on and the shape of this curve is crucial in determining the level and volatility of prices. Once demand is known, marginal energy costs for hours in which there is no congestion is driven by the intersection of the fixed demand and the point along supply curve. Eventually, when all capacity is used, the supply curve becomes a vertical line where output cannot be increased at any price because the maximum amount of capacity has been reached. The next chapter delves much further into the supply curve covering topics such as marginal versus average heat rates, variation in hydro energy and uncertainty with respect to plant outages.

Use of Short-term Marginal Cost in Forecasting

Implications:

When there is surplus capacity in a market with many suppliers, competition will be intense and price will move to short run marginal cost that does not cover capital costs of new equipment. This is the concern in financial models when surplus capacity exists in a market. A market can quickly move to this condition

and stay there a long time as demonstrated by the financial crisis. Example of refinery margins that do not justify construction of new capacity for extended periods.

When capacity is constrained and demand is growing, prices can remain above the levels required to build new capacity. The level above which prices are above those required to allow construction of new capacity may produce very high returns and last for long periods depending on the construction period of new equipment. But it is very dangerous in financial models or valuation analysis to assume that these levels can last indefinitely.

If markets are efficient and suppliers do not hold back capacity, prices should equal marginal cost. However, virtually no market is always in equilibrium and perfectly competitive where prices are precisely the same as marginal cost at each instant. A serious debate is arising as to whether electricity markets really do have sufficient competition to drive prices to marginal costs. There are questions as to whether Enron manipulated natural gas and electricity prices through with holding supply – something that would not have been possible if Enron did not have market power. In Great Britain, analysts have questioned whether the lack of competition in electricity leads to prices significantly above marginal cost.   The issue is relevant in the context of forward price projection in that we must forecast prices from marginal cost. If we understand the difference between marginal cost and price, we can use this information to make forecasts from marginal costs.

Once the exercise of calibrating prices to costs is finished, forward price projection involves two steps. The first step is projecting changes in marginal costs through forecasting changes in supply and demand curves. The second step is evaluating differences between marginal cost and prices and evaluating whether these differences will continue. Power pools in the U.S., U.K., and other places in the world use a dutch auction that mimics the process of determining prices by measuring the cost of the most expensive unit running on the system. However, instead of using variable costs, the pools allow participants to make bids that do not necessarily mirror the cost of the unit. The bidding strategy of companies, such as holding back a block of capacity for very high prices, can cause market prices to deviate from marginal cost.

Whether or not prices precisely match marginal cost, simulation of marginal cost provides guidance for developing forward price curves. Marginal cost analysis should be used in the development of forward prices even if markets are not perfectly competitive. If we know that prices will be a certain amount above or below marginal cost, or that prices will be a certain percentage above or below marginal cost, it is still crucial to forecast marginal cost in order to quantify the effects of changes in the structure of the market. In other words, changes in marginal cost due to changes in the supply curve or changes in demand will be highly correlated to changes in market prices. Therefore, even if prices are higher than marginal cost because concentration of firms creates market power, if demand increases or a plant outage causes supply to decrease, one would still expect changes in market prices to mirror changes in marginal cost.

Market Price = Marginal Cost + Adjustment factor
Or
Market Price = Marginal Cost x (1 + Adjustment factor)

To value an investment, price forecasts are needed for long periods of time and, depending on the type of plant being valued, price forecasts are also required for sub-periods over the course of each year in the case of electricity discussed above – often for each hour of each year. If marginal costs are to guide price forecasts, then marginal costs are required from these different time frames – over the long-term as well as for detailed time periods. This section introduces the topic of how to measure marginal cost by presenting the basic formulas that have been used in the industry to measure marginal costs. Later sections expand the analysis through describing issues with different components of the marginal cost formula and describe alternatives to the traditional approaches.

Historically, the marginal cost of generation has been measured in the electric industry by separating costs into marginal energy cost and marginal capacity cost as summarized in the formula above. Marginal

energy cost includes fuel, variable operation and maintenance and environmental costs of plants that must be operated to meet energy consumption requirements. The marginal capacity costs are measured by computing a hypothetical rental cost for a peaking plant that represents the lowest cost way to insure that enough capacity is available to insure that consumption requirements can be met at the peak time.

To compute the cost of producing energy to meet consumption requirements, the denominator is a small change in consumption of electricity and the numerator is the cost of that small change in demand. The energy cost is computed by recognizing that plants which will change the way they operate given small changes in consumption are the last plants to dispatch which are generally the plants with the highest operating cost. Once marginal cost is computed for a single hour, it can be averaged over the course of a year using the following formula:

Marginal Energy Cost in a Year =
$\sum_{\text{Hours}}$ (Cost of Last Unit to Dispatch in Each Hour)/Hours of Use in a Year

The capacity cost part of the marginal formula requires definition of how rental charges on a peaking plant will be computed and how units of capacity can be computed. If the price only covered marginal energy costs, the total capital and operating costs of plants would not be able to profitably operate. The rental cost is defined as the carrying cost of a plant and the units of capacity are defined as the number of hours in a year that capacity in a system is stressed. The denominator of the capacity cost piece of marginal cost is traditionally made by attributing some hours to peak periods when use of electricity is relatively high. The rationale for this allocation between time periods is driven by the fact that electricity cannot be stored, demand cannot be delayed, and the opportunity cost of outages experienced by customers is very high. For these reasons, electricity capacity is required to produce energy in peak periods, even though the capacity is not necessary for most times of the year. Therefore, if a customer reduces usage during a congested peak period, the need for construction of new capacity should be reduced. On the other hand, if usage is reduced at off-peak times, there is no change in the requirement to build capacity and there is no marginal capacity cost. This means the marginal cost of capacity during periods of time when not all of the capacity in a system is needed is zero. For usage that occurs during non-congested non-peak periods, the surplus of available capacity built for peak usage is simply a by-product of the need to have capacity available for peak periods. Therefore, the marginal capacity cost of off-peak capacity (the by-product of on-peak capacity) is zero.

Marginal Capacity Cost = (Annual Carrying Charge of Peaking Unit +
Annual Fixed Operating Cost of Peaking Unit)/Hours of Peak Use in a Year

The definition of marginal cost in the above formula is known as the “peaker” method and is of limited practical use for analysis of future market prices or plant valuation. The approach does not consider the status of existing supply (for example, whether there is excess capacity or an uneconomic capacity mix). The approach also ignores the services of peaking plants that are not related to insuring capacity is available (a new combustion turbine may produce energy for quite a few hours over the course of a year). Finally, the approach crudely allocates the cost of a peaking plant to a set of peak hours. A better definition of long-run marginal cost of generation includes the opportunity cost of three economic resources – fuel, variable operation and maintenance costs and the forgone “utility” during capacity shortages that results from consumption of electric energy.

Next move to how the marginal cost concepts can be practical. If do not need to attribute to individual hours, can simply compute the cost of a single plant that will be the marginal unit in the system. For this need do define carrying cost or rental rate. In more complex situation where multiple types of plant can efficiently meet new load, need to understand how optimal type of capacity is constructed when load changes. Finally, when need to evaluate hourly prices, the full formula with costs allocated to hours must be computed. Transition – need to compute annual carrying cost; next equilibrium long-run prices in the long-run.

Long-Run Marginal Cost and Congestion

Marginal cost is a pre-requisite to analysis of market prices. If marginal cost theory is applied in evaluating the future level of competitive market clearing prices, it is not useful to make artificial distinctions between short-run cost, long-run cost, incremental cost, detrimental cost or avoided cost. Participants in the market make incremental consumption and production decisions on a short-term basis through evaluating their variable opportunity costs relative to market clearing prices. Costs that vary in the short-run together with congestion costs that arise during capacity constrained periods are therefore the relevant guide for measuring competitive spot prices. Costs of building new capacity must be recovered to a significant degree from prices that occur during congested periods.

Economists often distinguish between long-run marginal costs and short-run marginal costs when analyzing prices and output in an industry. The long-run is typically defined to be a time period in which new capital stock can be deployed, while the short-run is a period in which the existing capital stock is held static. This distinction between long-run and short-run is problematic if one is to use value drivers and making price forecasts that are a part of cash flow projections. If marginal costs are to be calibrated to market clearing prices but we then have to then ask whether the marginal costs are short-run marginal costs or long-run marginal costs, the marginal cost analysis is pretty much useless as a practical guide for price forecasting or valuation purposes.

Nobel laureate William Vickery considered the question of how to connect the short-run and the long-run when calculating marginal cost. He asserted that the only relevant definition of marginal cost is the short-run cost and that the costs of adding new capacity must be somehow incorporated in the short-run marginal cost. Through working with this definition, the frustration of having to distinguish between long-run cost and short-run cost is avoided, particularly for things like telecommunications, air transport, electricity and many other things that cannot be stored. Vickery notes that this calculation of capacity cost can be accomplished through determining the cost of impaired service quality during periods when capacity is constrained (if the product can be stored, then the cost involves storage and cost of capital.) The implications of his writing is that recovery of capital can in fact be incorporated in short-run costs by allocating the capital costs to periods during which there is not sufficient capacity to meet the entire demand, defined as periods of congestion. Vickery wrote:

> *In an ideal world, all prices would be set at short-run marginal social cost so that purchasers would have proper indications to make efficient choices among the various alternatives. If this condition is not met, it would theoretically be possible to improve the lot of everyone by increasing the consumption of goods having prices in excess of short-run marginal cost and reducing the consumption of goods for which the reverse is true…*
>
> *Short-run marginal cost … at a given instant and location has two main components: the cost to the [producer] on the one hand, and the cost in terms of impaired quality of service to other customers on the other…The cost of providing added [goods] to one customer when capacity is being fully utilized is the depriving of another customer …*[7]

Vickery applied this explanation to electricity power, but it can just as easily be applied to taxi service, airplane tickets, or toll roads (Vickery would ponder marginal costs of different things which can be a useful and challenging mental task when studying prices.) If short-run marginal costs do not include the component for impaired quality during periods when demand must be constrained, then marginal costs cannot recover capital costs for new investments. Where prices are set at the variable opportunity cost of production without a return to capital, new capacity will never be constructed and the market-determined price does not allocate resources in an optimal manner. The congestion, whether it be traffic jams, insufficient electric power, long waiting periods for wind mills, inability to make phone calls, or insufficient airplane seats will just get worse and worse. In computing the value of impaired quality, Vickery

[7] See Kahn, page ___.

reconciled recovery of capital costs with short-run marginal costs through describing hypothetical hourly rental payments for capital equipment during congested periods:

> *The marginal cost assignable at a given time … can be obtained by imagining that equipment could be rented by the hour in a competitive market, assuming that the equipment could be transferred costlessly from a depot to place of use and back."*[8]

When renting equipment by the hour, the equipment owner whose business it is to rent out equipment would have to recover the fixed costs of his equipment including all of his financing costs in congested periods as the equipment would be transferred back to the depot in periods when there is no congestion. In doing this he would somehow have to predict how many hours his equipment would be used at various prices. If his rental rate was too high, he would lose business. If his rental rate was too low, he could not recover his own capital cost. From the perspective of the companies renting out equipment, rental rates that recover fixed costs of financing equipment over short time periods when all capacity is utilized would surely be very high. Recovery of these rental charges through marginal cost allocated to congested time periods would then also be very high. Practical application of Vickery's ideas to measurement of marginal cost requires one to define times during when capacity must be rented (constrained periods) as well as hypothetical short term rental rates that recover the cost of capacity.

Vickery's ideas can be directly applied to the pricing of electricity in competitive markets. While he made his wrote his ideas years before de-regulated pricing of generation, his statements extreme price spikes since capacity costs of generating capacity built for providing power only during high demand periods must be recovered only in the congested hours. The definition of marginal cost that integrates short-term cost with long-run cost also explains the high volatility in capacity prices that remain near zero form many periods and then suddenly spike. This notion that there is only one relevant measure of marginal cost also explains how price spikes recover capital investment and at the same time cover only short-term variable costs of operation.

The issue of how prices derived from short-term marginal cost can compensate owners for capital investment is not new and it is not unique to electricity. Indeed, more than two centuries ago Adam Smith suggested that market clearing prices could be established for toll bridges – capital intensive investments with very low short-term marginal cost and varying traffic usage that cannot be provided by carrying inventory. Since then, the pricing of capital intensive investment has continued to be an intriguing subject for economists. The explanation below presented by Alfred Kahn recounts a famous toll bridge example which considers how prices should be established in different time periods.

Congestion Pricing and Recovery of Toll Bridge Capital Costs

Economists have long been bemused by Dupuit's and Hotelling's historic example of the bridge and the strong case that they made against maintenance and capital costs that do not vary significantly with the rate of utilization. [This implies that the marginal cost of crossing the toll bridge is zero.] But what if charging a zero toll would, at least at certain hours of the day, produce such an increase in traffic that cars lined up for miles at the bridge and crossing took an hour instead of a few minutes? In that event, the short-run marginal cost of bridge crossings, at those [congested] times, is not zero. It can be envisioned in terms of congestion: the cost of every bridge crossing at the peak hour is the cost of delays it imposes on all other crossers. Or [the cost of crossing at congested times] can be defined in terms of opportunity cost: if A uses the bridge at that time, he is taking up space that someone else could use; therefore the cost of serving him is the value of that space or capacity to others who would use it if he did not…

The off-peak users impose no costs on society, provided their demand is sufficiently slight and inelastic that even at a zero toll no congestion occurs at the time they cross over. The incremental costs of serving off-peak users are zero and may remain so indefinitely. This is the case even if the off-peak demand grows over time and continues to be satisfied without congestion only because the bridge's capacity is being expanded. The necessity for expansion is imposed by customers at the peak hours. It remains true that if one or all of the off-peak users ceased to cross the bridge, briefly or permanently, society would be saved no costs whatsoever.

Notice how the intensity and elasticity of demand help determine the level of marginal costs. For those hours of the day at which demand is insufficiently strong or responsive to a toll covering only operating expenses, marginal costs include only those operating expenses; for those times of the day at which demand is strong or so responsive to a lower toll as to cause congestion, marginal cost necessarily includes capital costs as well.

The description of pricing during congested pricing periods described above is not applicable to all products. Much of the problem is created by the fact that demand varies by time period and the benefits of crossing a bridge cannot be moved from one time to another. When products can be stored in inventory such as clothes, jewelry, food, real estate or oil, the problem of congestion is not a major issue. For these products, as long as demand is increasing, the price must cover capital cost or inventory stocks will not be replenished. Further, the toll bridge example must be modified if it is applied to situations where a product can be produced with multiple different types of technology. If there is only one type of technology and consumer demand in various hours during the year either causes the plant to be fully used or partially used, the toll bridge example can be applied in a straightforward manner. Computation of marginal cost using these congestion pricing concepts requires definition of congested periods when the activities of one consumer cause some kind of cost to another, computation of financing charges that recover costs in short periods, estimation of price elasticity during congested periods and the cost structure of production plants used to produce electricity.

Carrying Charges and Measurement of Marginal Cost

The marginal cost based pricing model described above where clearing price is variable cost of the highest cost unit that is being dispatched has a conceptual flaw because investors in new generating plant do not earn a reasonable profit level in the long-run. The fact that the model is not sustainable can be demonstrated by considering how investors in new peaking capacity earn profits on their investment. If electricity prices are limited to the marginal operating cost of most expensive generating unit operating, the highest level prices can reach in any hour is the operating cost of the capacity with the most expensive variable operating cost -- peaking capacity. In hours when the new peaking plant does not operate, the plant does not earn a profit. In hours when the plant operates, the price is equal to its variable operating cost and the plant also does not earn a profit. This means that owners of a peaking plant do not earn sufficient revenues to make contributions to the fixed costs of maintaining the plant much less the fixed capital costs required to finance the new plant.

Before delving into the details of analytical models that project long-term prices, it is instructive to review a few economic principles with respect to price determination and capacity expansion in commodity markets. The basis for modeling prices is that prices in competitive markets must ultimately be sufficient to cover the cost of constructing and operating new plants. A forecast where prices are continue to be above cost for an indefinite period is not logical because developers then have an incentive to build more and more new plant which will cause prices to decline. Similarly, forecasts that result in price below long-run marginal cost implicitly or explicitly assume investors construct new plants that lose value. Models that assume developers can continually earn high profits or models that assume losses persist over an indefinite period are not plausible over a long time period. The only rational long-term price forecast is a model that converges to an equilibrium level where investors earn returns that correspond to the cost of capital associated with new plants.

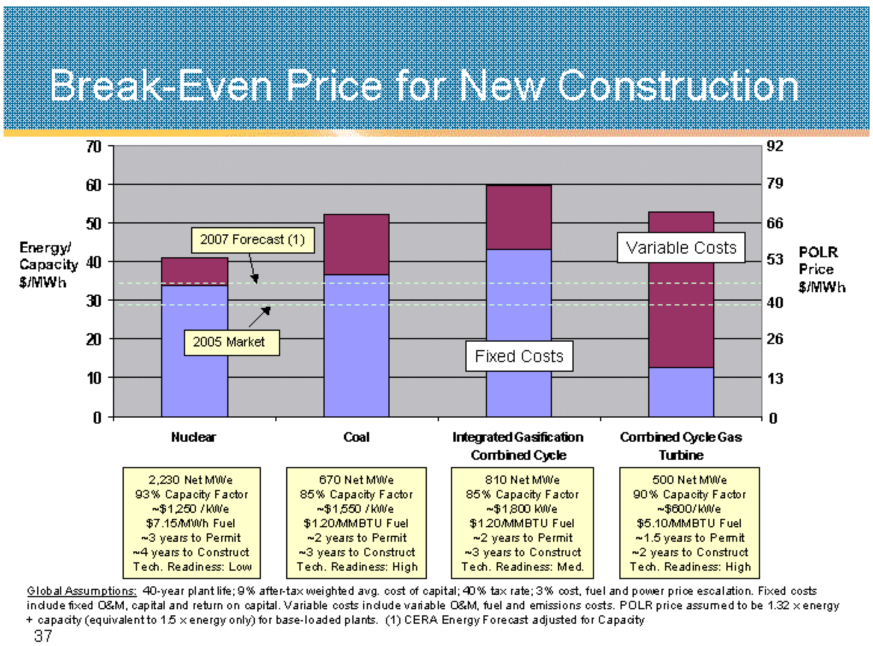
Idea here – simple cost of one type of capacity as a check. Use the Exelon graph as an example. Information base that is available. Simple formula to compute average price and importance of the carrying charge rate. Other industries airline industry, oil industry etc.

Calculation of marginal capacity cost requires converting the total investment cost of a new plant to costs on a periodic basis (recall the example above where rental rates for equipment determine the marginal capacity cost.) To apply the rental of equipment analogy in practice, rental rates are computed per year, per month and per hour. Conversion of capital costs to annual levels also permits one to determine whether market prices over the course of a year will be sufficient to yield the required return of investors. The percentage factor that converts an investment cost into an annual amount is known alternatively as the annual capital recovery factor or the annual carrying charge rate. From an accounting perspective, the

carrying charge rate is the sum of depreciation expense plus operating income plus income taxes divided by the debt and equity used in financing the investment.

This carrying charge factor converts the cost of building a plant into a series of annual, monthly or hourly costs that recovers the amount of investment plus a rate of return that compensates investors for taking a risk in building the plant. The concept of an annual carrying charge rate is frequently used in the utility industry for assessing the relative costs of investments with different cost structures (see the screening analysis below).

Constructing an electricity plant is very expensive and it can take decades for owners to receive enough cash to cover their initial investment plus a rate of return that meets their financial criteria In the example below four plant types are compared with different capital and operating costs.[9]



Mechanics of Carrying Charge Calculations

The remainder of this section addresses how to compute the carrying charge rate – the annual level of prices revenues required to compensate investors for the initial cost of constructing a facility. If one knew the required price level that meets the financial criteria of investors, then the carrying charge rate would be the level of annual revenues implied by the price divided by the total construction cost.[10] Carrying charge factors that recover the investment and cost of capital over the life of a plant require a variety of finance and tax assumptions that span the lifetime of an electricity generating plant. The level of carrying charges depend on the cost of equity and debt capital, the income tax rate, the property tax rate, the lifetime of the asset, the construction period, the life and method of tax depreciation, and the capital structure. In computing carrying charge for purposes of evaluating the cost of an investment relative to market prices, the time pattern of recovery over the long lifetime of a plant also affects the calculation. The time pattern

[9] Presentation by Exelon to Edison Electric Institute Finance Meeting; May 2005.

[10] The manner in which the market monitor for PJM assess the performance of installed capacity markets illustrates how carrying charge rates are used in practice. The market monitor compares the annual level of capacity prices in the PJM market with the annual cost of constructing peaking capacity where the annual cost of peaking capacity is determined through multiplying a carrying charge rate by the investment cost of peaking capacity.

of annual revenues relative to construction cost should replicate year-by-year price trends that are expected to occur in competitive markets which depends on projected inflation and expected real rates of productivity improvement of competing technologies. Finally, analysts must decide whether the carrying charge required in pricing and investment models should be for the initial year, the average over the life of the asset or the levelized carrying charge.

In theory, the level of the carrying charge rate should be independent of the manner in which an asset is financed. This theory involving the conservation of risk derived from Modigliani and Miller[11] is described in Chapter 6 along with alternative approaches that can be used to measure the appropriate cost of capital for a plant. In practice, the theory of independence between financing and valuation has not been applied and investments have been made in the electricity industry where financing costs of the entity constructing the plant have a large influence on the analysis. Historically, the financing structures used to build plants have been very diverse ranging from state ownership or cooperatives that use all debt financing and are able to obtain low interest rates to merchant power plants that require a substantial equity base and are subject to the scrutiny of credit analysts. Although the alternative financing structures allocate risks in different ways to consumers and investors and should not theoretically affect valuation, differences in the financing structures are in used in practice to compute carrying charges.

The effect of alternative financing structures on carrying charge factors is illustrated below assuming no inflation and no changes in productivity over the lifetime of the investment. Carrying charges are computed using a project finance model where the required price is flat over time and it is computed through finding the level that corresponds to the required rate of return. The table below shows assumptions for various alternative financing structures including a cooperative with zero taxes, an investor owned utility company with a capital structure that remains constant over the life of the plant to project financings with a contract structure and a merchant structure. In theory, the carrying charge should depend on the inherent risk of the technology rather than the type of entity financing the plant. Quantifying the risk of different technologies should be incorporated in carrying charge rates and is a major topic addressed in subsequent chapters. Section 1.1 of the workbook describes how to make the computations in this model with alternative assumptions.

Assumptions for Carrying Charge Analysis

	Coop	IOU	Independent Developer with Contract	Independent Developer/ Merchant
Initial Debt Percent	100.0%	50.0%	85.0%	60.0%
Debt Cost	6.5%	7.5%	8.5%	8.5%
Required Equity Return	12.0%	12.0%	14.0%	14.0%
WACC/Project IRR	6.50%	8.25%	8.0%	9.7%
Debt Term	30	30	30	20
Loan Grace Period (Years)			5	0
Plant Life (Years)	30	30	30	30
Tax Rate	0.0%	40.0%	40.0%	40.0%
Tax Life (Years)	15	15	15	15
Tax Depreciation Method	NA	MACRS	MACRS	MACRS
Inflation Rate	3.0%	3.0%	3.0%	3.0%
Property Tax Rate	1.0%	1.0%	1.0%	1.0%

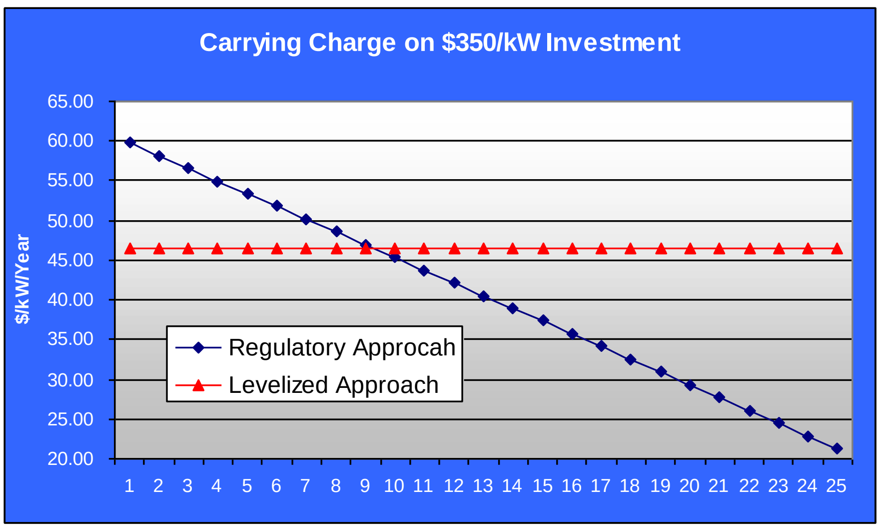
The table shows that levelized carrying charge rates vary between ___% for the 100% leveraged structure where revenues must just cover interest costs to ___% for

[11] Merton Miller and Franco Modigliani (1958) radically changed the way in which risk is considered through their work on debt and equity financing.

Time Pattern of Carrying Charges without Inflation and Productivity Changes

Mistakes in computing annual carrying charge rates can distort investment decisions. If inflation is not reflected in the carrying charge rate when assessing the cost of an investment, investors will believe prices have to be higher than they really must be in order to compensate owners. Alternatively, if investors do not consider future obsolescence in computing the carrying charge rate, they may inappropriately believe prices adequate to support an investment when the market prices are in fact not high enough.

In a world with no inflation or productivity changes, the level of capital recovery depends on cost of capital, tax rates, tax depreciation and the life of the asset.[12] Without inflation, there are two general methods for computing carrying charges once the investment cost, the cost of capital and tax parameters have been established. The first method termed the "regulatory approach," yields the same return on equity in each year. The second method is computing a level price amount to recover capital from year to year that yields an internal rate of return equivalent to the cost of equity capital. I label this method as the "levelized carrying charge" approach. The mechanics of this approach involve setting up a cash flow worksheet that includes income taxes, interest costs and cash flow to equity over the plant life. A cash flow model is used to derive the capacity price level that will permit investors to earn their hurdle rate of return. The cash includes investment made to construct the plant and income tax payments. The cash flow analysis covers the lifetime of the investments and reflects tax depreciation parameters allowed for the plant. Required revenues are computed on an iterative basis to establish the amount that yields the return level.



The regulatory approach was implicitly used in computing revenue requirements under rate of return regulation. This method yields a declining pattern of cost recovery over the lifetime of a plant. As equity investment declines because of either accumulated depreciation and accumulated deferred income taxes, the money required to support the this pre-determined return on equity also declines. Over the lifetime of the investment, the cash flow to equity declines, but the internal rate of return on equity cash flow produced by the plant equals the required rate of return on equity. The accompanying graph demonstrates the year by year prices required to support an investment of $350/kW assuming a return on equity of 12% is earned in each period, a real debt cost of 7.5%, an income tax rate of 40%, straight line depreciation and debt leverage of 50%. The levelized line on the graph is computed by deriving the price required to yield an internal rate of return on equity of 12%. The first year carrying charge rate using the regulatory approach is 17.08% that results in an annual capacity charge of $59.8/kW/Year while the levelized method results in an annual capacity charge of 13.28% or $46.5/kW/Year.

[12] In a situation with no inflation, the cost of capital is only the real rate without inflation. For example, if the nominal rate of return in 10% and the expected inflation rate is 3%, the real rate of return is (1.10/1.03) or 7%.

If the productivity of the asset relative to other new investments does not change over the life of a plant (i.e. there is no economic obsolesce or changing maintenance requirements) the year-by-year capital recovery consistent with competitive markets is simply a level amount in real terms over the life of the plant. The declining pattern of capital recovery therefore does not generate prices that would occur in competitive markets. A “proof” that the prices are not sustainable is that if one company is building a new plant while another is towards the end of its useful life, the model would suggest two different market clearing prices – a violation of the basic principle of a single price in economics. Indeed, the declining capital recover pattern in the “regulatory” model has created significant distortions between capital intensive and fuel intensive plants, has caused “rate shock” and has resulted in significant misallocation of resources. In a world without inflation and where the productivity of an asset does not change over the life of the asset, the only capital recovery model that is consistent with a single price for the same product is a level recovery over the life of the asset.[13]

Incorporation of Inflation in Carrying Charge Rates

If levelized carrying charges are computed using "nominal" cost of capital -- one that implicitly includes a component for expected inflation – this method produces distorted results for purposes of simulating prices and assessing cost recovery. In this section I demonstrate that for the purpose of evaluating market prices, the capital recovery calculations must be adjusted so that the dollar amount of capital recovery increases with expected inflation over the life of the asset. In economic parlance, this simply means the prices are level in real terms. While computing real carrying charge may be obvious to economists, the mistake is made so often in practical applications, it warrants some discussion.

If a levelized capital recovery rate is used in evaluating prices, the “nominal” carrying charge is multiplied by the current dollar value of plant investment. The calculation results in an amount that is used to assess whether market prices for the current year enable capital recovery of a new plant. Presumably, in the next year, the same calculation would be made – multiplying the nominal carrying charge by the now inflated investment cost. However, since the investments are priced at the new price levels – including increases in investment cost reflecting inflation – the capital recovery amount would increase in the next year. Therefore, use of a level nominal carrying charge calculation accounts for inflation twice -- once in the carrying charge, and again by using current price levels in measuring plant value. Problems with the method of multiplying nominal discount rates by current prices have been noted by noble laureate William Vickery:

> In a context of inflation, conventional methods of accounting and rate of return result in a front-end loading of costs that is at odds with efficient pricing….A treatment more in line with efficient pricing would be to … combine real depreciation … with real interest …[14]

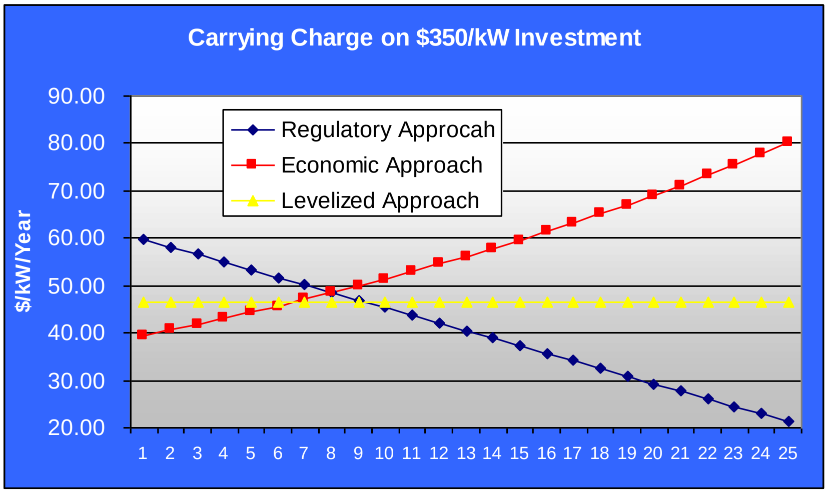
Dr. Vickery continues by observing that methods of multiplying nominal cost of capital by current prices "result in serious distortion."

The example introduced in the last section can be adjusted to rectify problems associated with double counting of inflation. I label the approach that corrects for expected inflation as the economic approach. Correcting the levelized approach for inflation involves deriving the initial year price -- with subsequent prices escalating with inflation -- that results in the target rate of return. If the expected inflation rate is

[13] The “traditional” regulatory model where prices are set from net investment multiplied by the weighted cost of capital can be adequate for assessment of alternative investments. For purposes of investment evaluation in a world that does not have competitive forces, this does not distort investment analysis. However, in assessing the time path of competitive price levels that must recover investment costs, the “regulatory” approach has serious flaws.

[14] Vickery, William, "Efficient Pricing of Electric Power Service". Resources and Energy 14. 1992. North Holland

above zero, the initial year price computed using this method will be lower than the levelized price that is constant in each year.[15]



Assuming a rate of inflation of 3% per year, a nominal required internal rate of return of 12% and a debt rate of 7.5% results in price patterns as shown in the accompanying graph. The graph includes the levelized carrying charge approach, the approach where prices inflate as described in this section and the "regulatory" approach described above. Even though I show the carrying charge for each year on the graph, the only number directly used in assessing the investment cost relative to market prices is the initial year price. The method that accounts for future inflation in carrying charges results in a first year carrying charge rate of 11.25% and a capacity charge of $39.4/kW/Year -- 15% below the levelized method and 34% below the regulatory method.

	Coop	IOU	Independent Developer with Contract	Independent Developer/ Merchant	Independent Developer/ Merchant
First Year Capacity Price ($/kW/Year)					
Levelized Approach	$ 28.14	$ 42.36	$ 37.70	$ 49.40	$ 71.21
Inflating Approach	$ 20.33	$ 31.58	$ 30.47	$ 39.95	$ 57.53
First Year Carrying Charge Rate Percent					
Levelized Approach	8.04%	12.10%	10.77%	14.11%	20.32%
Inflating Approach	5.81%	9.02%	8.71%	11.41%	16.44%

Over the past decade, many investments have been financed on a project basis. In a project finance situation, the debt must be repaid to yield an internal rate of return on equity sufficient to justify the initial investment. The project finance framework can be effective in measuring the required capital recovery because it is representative of real world financing in competitive markets and because it provides a method by which prices can be associated with a particular investment. Using an internal rate of return of 14% on equity, and financing parameters representative of a contract and merchant priced projects results in carrying charges shown in the table below. I have included a scenario with 100% equity financing because of the difficulty of obtaining debt financing on peaking plants with no contracts. Operation of the project model is described in Section 1.2 of the workbook where you can input different return levels, leverage amounts and other factors and assess the resulting capital recovery requirement.

[15] The constant real carrying can be reconciled with project finance models through a debt repayment structure combined with a debt reserve that is used to make interest payments in early years of the plant life.

Impacts of Changing Productivity Changes in Carrying Charge Rates

Over the long lifetime of an electric generating plant, the nature and productivity of generating technology can change dramatically. Productivity can be defined as the dollar value of fuel and capital inputs relative to the amount of electricity produced. If the productivity of new generating plants increases relative to existing plants, the effective revenue the plant can earn from competitive prices to recover capital cost will decline. Changes and variability in productivity are important issues in time series analysis discussed in Chapters 2, 5 and 6. New technology of electric plants should result in a lower real capital cost or better heat rates of the plants (the fuel input relative to the electricity output). Carrying charge rates should incorporate expected improvements in productivity over the economic life of a plant. If the expected productivity of future new plants increases relative to the current technology, all else being equal, the amount of required capital recovery per year in the early years of the life of a plant should increase.

Assuming new plants are subject to the same environmental constraints as existing plants, productivity of new plants should improve relative to existing plants. If management systems remain constant, firms can always choose to employ existing technology and achieve the now current levels of productivity. In the future, productivity can either stay the same or get better. One would not after all expect managers to employ inferior systems and technologies. Productivity improvements in electricity generation are noted by Peter Rigby of Standard and Poor's:

> Technology also presents its special forecasting problems. Some models that Standard & Poor's has reviewed assume no technological improvement in generation technology. GE's recent announcement of a 5% efficiency gain in its new "H" series gas turbine emphatically underscores the failings of the static technology assumption. A review of the US Department of Energy's Clean Coal Research Program also suggests that static technology assumptions, even for coal, may be weak. The coal research program is targeting coal fired generation efficiencies over 65% by 2015 – a target well above today's typical 39%.[16]

Adjusting carrying charge rates for changes in expected productivity is straightforward from a theoretical perspective. However, practical application of changes in productivity is rarely addressed in pricing and financial applications. In Appendix 1 to this chapter a framework is presented for computing expected changes in productivity to electricity generation. The expected productivity changes relevant for computing carrying charge rates are amounts that are projected to occur rather than risks that the productivity may vary above or below the expected level. The variability in productivity is incorporated in the carrying charge through the risk premium inherent in the required cost of capital.

Long Run Marginal Cost for a Single Technology

A misunderstanding of long-run marginal costs has caused the destruction of massive amounts of capital in the merchant power industry. Price forecasts used by developers in Argentina assumed that an inefficient capacity mix would remain in place and low water flows. Market price forecasts in the Northeast US did not consider the dramatic increase in capacity that was occurring from plants being developed. These forecasts assumed prices in the long-run would be above the level required to operate and financing a natural gas combined cycle plant. Before addressing how marginal cost is affected by the capacity mix, the marginal cost of a single technology – a natural gas combined cycle plant -- is discussed. While this simplification does not reflect any optimization in capacity mix, the cost of a new plant is a good benchmark for evaluating the more complex analysis that considers multiple plant types. Some markets such as Singapore, Australia and New Zealand have used the cost of an NGCC to represent long-run marginal cost and form the basis for bilateral contracts.

[16] Rigby, Peter N. "Risks from Left Field: Is There a Problem with Pricing Models?" The 15th Annual Global Power Markets Conference. April, 2000.

Long-run marginal cost measured with a proxy of the cost of building and operating an NGCC plant involves adding variable costs to fixed charges and assuming that the plant operates at a level reflective of the load factor in a market. Assuming that fixed costs are computed from the carrying charge analysis above, the long-run marginal cost can be computed with the following formula:

Long-run Cost/MWH = (Variable Cost/MWH + Fixed Charges/MW/(8,760 x Capacity Factor)

In this formula, the fixed charges depend on the fixed O&M cost/kW, the carrying charge rate and the capital cost of the plant. Long-run cost assuming a 59% capacity factor, various different carrying charge assumptions and a series of gas prices is illustrated in the table below. Section 1 of the workbook describes how the calculations are developed using a project finance model, a data table and a macros.

Combustion Turbine Carrying Charge						Generation Price with 10% for Ancillary Service			
	Productivity Trend	Equity IRR	Carrying Charge ($/kW/Year)	Carrying Charge Rate	Fixed Charge ($/kW/Year)	All Hours Energy Price	All In Price at 100% Capacity Factor	Weighted Energy Price	All In Price at 100% Capacity Factor
75% Leverage	No	12%	47.43	10.54%	57.43	44.00	51.54	49.50	62.28
40% Leverage	No	12%	61.56	13.68%	71.56	44.00	53.39	49.50	65.42
75% Leverage	No	15%	53.63	11.92%	63.63	44.00	52.35	49.50	63.66
40% Leverage	No	15%	75.32	16.74%	85.32	44.00	55.20	49.50	68.48
75% Leverage	Yes	12%	54.64	12.14%	64.64	44.00	52.49	49.50	63.88
40% Leverage	Yes	12%	70.91	15.76%	80.91	44.00	54.62	49.50	67.50
75% Leverage	Yes	15%	60.66	13.48%	70.66	44.00	53.28	49.50	65.22
40% Leverage	Yes	15%	85.16	18.93%	95.16	44.00	56.49	49.50	70.67

Forward Prices and the Equilibrium Long-Run Marginal Cost of Generation

Extend analysis because not only one technology is used.

The hypothetical discussion above assumed that there are only two possible levels of demand in a year (100 hours of congestion and 8,660 hours of non-congestion) and there are only one or two types of generating plants. For actual systems, the level of demand varies in each hour and there are many plants with different heat rates, different fuel costs and different outage characteristics. In the presence of multiple different types of base load, cycling and peaking plants in a market region, marginal energy costs are computed from the intersection of a supply curve and a demand curve on an hour by hour basis. The supply curve is developed through ranking all of the plants in a region according to their variable cost. The demand curve is generally driven by weather and economic activity rather than by price in all but the very high load hours. The high cost of customer outages implies demand is very inelastic except for hours when the price is very high.

To illustrate the marginal cost based framework presented below, suppose you were asked to quickly make a long-term forecast of electricity market prices that will be incurred by an industrial facility that operates 24 hours a day and seven days a week. You are asked to make this forecast without a fancy hour-by-hour "multi-regional" simulation model. A natural place to start is by evaluating the current level of

market averaged for all hours in the past year. Next, you could estimate the level of prices at “equilibrium” where the price just covers the cost of constructing and operating new capacity. Finally, you could use the capacity status in the market and the demand growth to assess how prices will move from current levels to equilibrium levels. While this simple approach may not address specific plant outages, variability in price spikes, changes in hydro conditions profitability of individual existing plants or generating unit ramp rates, your simple model includes evaluation of actual prices, forward fuel prices and changes in productivity that affect long-term prices, and behavior of merchants that affect how prices will move to equilibrium.

This section presents a model for computing the long-run marginal cost of electricity using load duration curves and screening analysis of technology choice. By combining some of the tools discussed above -- carrying charge rates, marginal energy costs, and capacity costs with a load duration curve, a relatively simple framework for computing long-run marginal cost can be developed. The framework discussed below demonstrate how various marginal cost concepts can be applied in pricing analysis and it introduces some of the general issues associated with the more detailed forward price models presented in the next two chapters. Finally, albeit simple, long-run marginal cost analysis can be an effective tool in assessing whether complicated forward pricing models with multi-regional transmission constraints, volatility premiums, price spikes and Monte Carlo simulation of plant outages are producing reasonable results.

To use long-run marginal cost in evaluating price forecasts, the simple framework begins with marginal cost analysis in current markets – point A. Next, long-run marginal cost with an optimal capacity mix is computed – point B. Long-run marginal cost should be at a level that promotes construction of efficient new plants with multiple technologies and it should reflect varying loads throughout the year. Finally, with current prices – point A -- and equilibrium long-run marginal cost – point B -- established, the simple framework should address how and when prices will move from current market levels to equilibrium.

Current Energy and Capacity Cost Levels

The traditional way marginal costs, prices and many other issues have been evaluated in the utility industry is to separate the analysis between capacity costs and energy costs. Marginal cost of energy is defined as the lowest variable cost of energy at generating units not currently producing energy for other uses (which is the same as the highest variable cost unit that is operating.) Capacity cost can be defined as the lowest cost of available capacity to provide “insurance” that energy will be available drives pricing of capacity. For example, electricity prices to industrial customers around the world are almost universally separated between demand charges for capacity and energy prices for energy usage. This conventional method of separating capacity and energy costs and prices is often still applied in pricing and valuation analysis, but it is also possible to evaluate market prices that combine energy and capacity prices in one number through “financially firm” market prices.

Current energy prices are related to marginal energy costs which in turn are the variable cost of the most expensive increment of capacity that is generating energy in any time period. If not all of the available generating units on a system are operating, marginal energy costs are defined as the most expensive cost of the generating unit that is operating in an hour. During low load periods (assuming no market power), market prices are bid to the marginal cost levels. During capacity constrained periods when all generating units are operating, the marginal cost of energy is not the cost customers would be willing to pay to be in the group of customers that is not curtailed as explained in the interruptible analysis below. These subjects are addressed in detail in Chapters 3 and 4.

One way to define the marginal capacity cost is the amount paid for firm electricity over and above the price of interruptible energy. Using this definition, the capacity price is the rental cost of can be thought of as the cost of "firming-up" interruptible energy prices and guaranteeing that energy will be delivered. While the nature of capacity prices may change in a competitive market (i.e. capacity prices may not be expressed in terms of dollars per KW-year), some level of capacity price must exist to keep existing plants operating and to promote the construction of new plants.

To illustrate computation of current market prices consider the PJM market prices in 2004. The monthly moving average for the all-hours price for energy was around $40/MWH while the on-peak price was about $50/MWH and the off-peak price was about $30/MWH. These energy prices do not include ancillary services have been approximately 10% of the energy price.[17] Although market prices for capacity are traded, the analysis below addresses what price level would exist if new peaking capacity were financed to make the firm-up the energy prices. If energy prices approximately reflect marginal cost, the combination of energy prices and the cost of firming-up capacity is the marginal cost that reflects the current capacity mix. The new peaking plant to be financed is assumed to have a capital cost of $450/kW (including all development, overhead and working capital) and fixed operation and maintenance expenses of $10/kW per year. The capacity cost of the peaking plant is computed using debt leverage of 40% and 75% and an equity rate of return of 12% or 15%. Finally, the carrying charge is computed with and without an assumed improvement in productivity.

Once the capacity cost is computed, the total price for energy used includes the total capacity price as well as the energy and ancillary charges. If the capacity charge is a component of price for every hour in which power is purchased, the effective capacity per MWH depends on the number of hours of electricity used as demonstrated by the following formula:

All-in Price/MWH =	Energy Price x (1+Ancillary Service Charge) + [(Capacity Price/kW x 1,000)/(8,760 x Load Factor)]

The table below shows the all-in price assuming electricity a 100% load factor and assuming the overall system load factor of 59%. The capacity cost is also increased by 15% to reflect the fact that a margin is added to capacity to assure that capacity will be available in case of an outage. Assuming alternative IRR criteria, leverage ratios and the productivity trend assumptions, the capacity cost ranges from the $57/kW/Year to $95/kW/Year. The range in capacity prices results in all-in electricity prices ranging between $51/MWH and $56/MWH for a customer who uses power for all hours. For a hypothetical customer who uses power in a manner that results in a 59% load factor, the energy price increases because relatively more on-peak energy is consumed. Further, because the total capacity cost must be recovered over fewer hours, the capacity cost increases. With the higher energy price and capacity price at the 59% capacity factor, all-in prices range between $62/MWH and $71/MWH.

capacity cost is $___/kW/Year. When this is spread across all hours of the year, the capacity price is $___/MWH which implies the all in price is $____/MWH. If it is assumed that the customer only uses power for half of the year, the energy price is a weighted average of the on-peak energy price and the off-peak energy price. hapter 5 describes how to compute current levels of capacity price in the market.

PJM Load Data			
		East	West
Averge		31,696.56	5,700.32
Maximum		53,737.00	8,437.00
Minimum		19,414.00	487.00
Median		31,367.00	5,670.00
Load Factor		59%	68%

Equilibrium Market Model and with Optimal Capacity Mix

The above calculations of marginal cost either assumed that the current mix of capacity will remain in place or that only combined cycle capacity will be added to the system. If costs can be reduced by construction and operation of multiple technologies, neither method reflects costs that would be incurred if

[17] PJM State of the Market, 2003. Published on the PJM website (www.PJM.com).

an optimal capacity mix is used in producing electricity. Use of a single plant to represent marginal cost will overstate long-run marginal costs if multiple technologies can be efficiently used to meet the requirements of a system with diverse loads. In a market framework, long-run marginal cost and market clearing prices will be driven by the value investors realize from constructing alternative types of new capacity. The equilibrium marginal cost converges to levels such that the net profit earned by investors is the same for developers who build different types of capacity.

Equilibrium long-run marginal costs must result in different types of technology having the same value. The value of plants is the difference between prices and variable costs. In the off-peak periods the capacity recovery is the difference between the market price and the variable cost summed over the hours that the plant operates. The model at the end of this chapter demonstrates the recovery of capital cost from different types of technologies with varying tradeoffs between capital cost and variable cost.

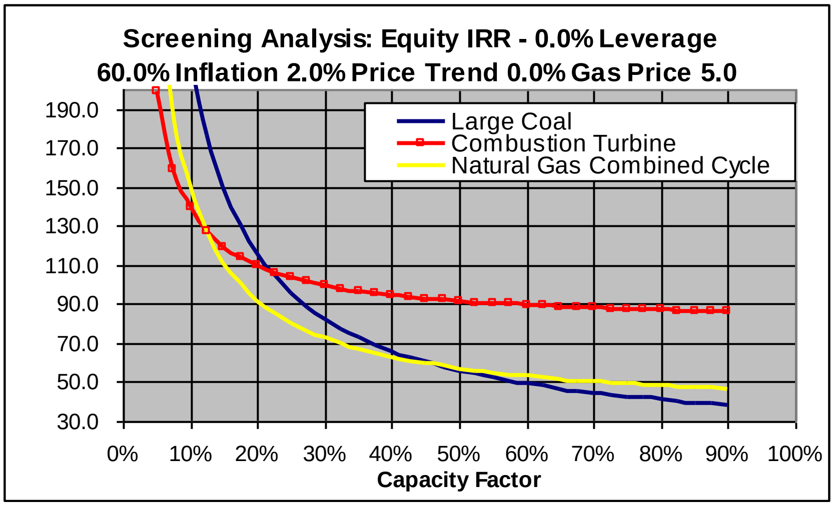
If the level of capacity and/or the mix of generating plants in a market region is not at an equilibrium level, the recovery of capital cost is not the same as the cost of new building plants. For example, if there is too much peaking capacity in a region relative to the economic optimum, the net cost of capacity for base load plants – after recovery of variable costs from off-peak prices -- is less than the annualized cost of a peaking plant.

Computation of long-run marginal cost in a market with multiple technologies begins with traditional screening curves and load duration curve analysis. Screening curves compute the total price required to earn the required return by various technologies at different capacity factors. The total price of each technology declines with higher capacity factor because fixed costs – fixed operation and maintenance as well as return on capital – are spread over higher MWH volumes. Once fixed charges are established from summing fixed operation and maintenance costs plus carrying charges, the following formula can be used to compute required prices.

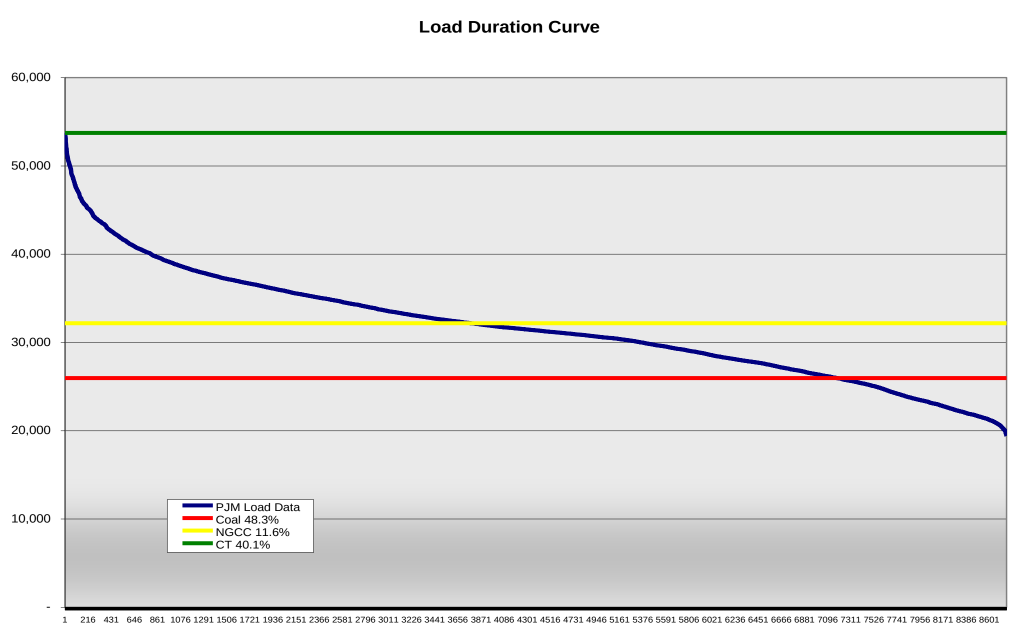
Required Price/MWH = (Variable Cost/MWH + Fixed Charges/MW/8,760)/MWH

At low capacity factors, the fixed charges have more effect on the total required price while at high capacity factors, the variable cost matters more. A screening analysis for three plants is shown on the graph below. The peaking plant has a lower all-in cost at low capacity factors and the base load plant has a lower cost at higher capacity factors.

	Plant Inputs to Equilibrium Model		
	Peaker	Combined Cycle	Coal
Capital Cost - Per KW	$450	$660	$1,250
Fixed Charge Rate - Per Year	9.50%	9.50%	9.50%
Annual Capital Cost ($/kW)	$42.75	$62.70	$118.75
Fixed Non-Fuel O&M Costs ($/kW/Year)	$5.00	$15.00	$30.00
Total Fixed Cost ($/kW/Year)	$47.75	$77.70	$148.75
Heat Rate (BTU/kWh)	11,000	7,000	10,000
Cost per MMBTU	$ 3.00	$ 3.00	$ 1.10
Fuel Cost/MWH	$ 33.00	$ 21.00	$ 11.00
Fixed Cost: $/KW/Month	$ 3.98	$ 6.48	$ 12.40



The second step of traditional analysis is integration of a load duration curve that defines energy production from various types of capacity. Load duration curve analysis involves sorting loads over a year from the highest level to the lowest level and placing various different types of capacity underneath the curve. Load duration analysis can be extended to incorporate the unscheduled maintenance outage of plants through computation of an equivalent load duration curve, but for now, a simple representation is used.[18] The load duration analysis "fits" different types of technology underneath the curve until total energy requirements are met. The total energy production divided by the number of hours and the capacity of the plant defines the capacity factor of the plants. Load duration curve analysis is illustrated on the graph below.



The question to be addressed in capacity expansion analysis and in computing long-run marginal cost is determining what mix of capacity should be used in filling the load duration curve. Three outcomes should

[18] See ____ for a discussion of how to create an equivalent load duration curve.

occur from computing the optimal mix. First, the capacity factor of the plants should match the capacity factors in the screening analysis. Second, the total cost including variable and fixed cost should be lower with the capacity mix than with any other mix of capacity. Third, the net value of each technology should be the same. Computation of the optimal mix can be made with the "solver" routine in spreadsheet programs once total cost is defined. Mechanics of computing the solver to determine the best mix of capacity is discussed in Section 1 of the workbook using the general approach below:

Set:	Capacity factor of each technology to level determined in screening curve
By Changing:	Weight of each capacity type
Subject to:	Weights greater than zero; weights sum to one

The use of load duration analysis has been around for a long time and it is very easy to accomplish with spreadsheet tools. This method can also be used to compute long-run marginal cost by adding two simple concepts to the analysis. The first concept is that the energy price in each hour is determined by the cost of operating the highest cost plant on the margin. This notion is discussed in detail in Chapter 3. The second concept is payment of a capacity price driven by the fixed cost of a peaking plant. This notion is explained in Chapter 4. Using the two simple concepts, a peaking plant does not earn anything from selling energy because the highest level energy prices can reach is the cost of running the plant. Energy and capacity prices are determined by the following two basic formulas:

Capacity Price = Carrying Cost plus Fixed O&M of Peaking Capacity

Energy Price $_{\text{Hour}}$ = Variable Cost of Most Expensive Unit Operating $_{\text{Hour}}$

In this model the net profit earned by a peaking plant is zero because the most it can earn by selling energy is zero and because the capacity cost equals the fixed cost (including the opportunity cost of capital.) Once the peaking plant perspective is established, a similar notion implies that the net profit should be zero for other plant types. For plants other than peaking plants, profit includes the amount earned from selling electricity at a price above variable cost aggregated on an hourly basis, less the fixed costs of the plant. If one type of capacity were more valuable than another type of capacity, the market would not be in equilibrium. This means that the value of new peaking capacity equals the value of building new combined cycle capacity which equals the value of building new base load capacity. For example, if the fixed cost of peaking capacity was $40/kW/Year, implying that all plants realize a capacity price of $40/kW/Year and if the fixed cost of NGCC is $113/kW/Year, the value realized from energy sales at market prices above variable costs of the NGCC plant must aggregate to $73/kW/Year ($113/kW/Year minus $40/kW/Year.) The notion that each technology should have the same value is shown by the following formulas:

Net Profit = Capacity Value + Energy Price – Fixed Costs – Variable Cost

and,

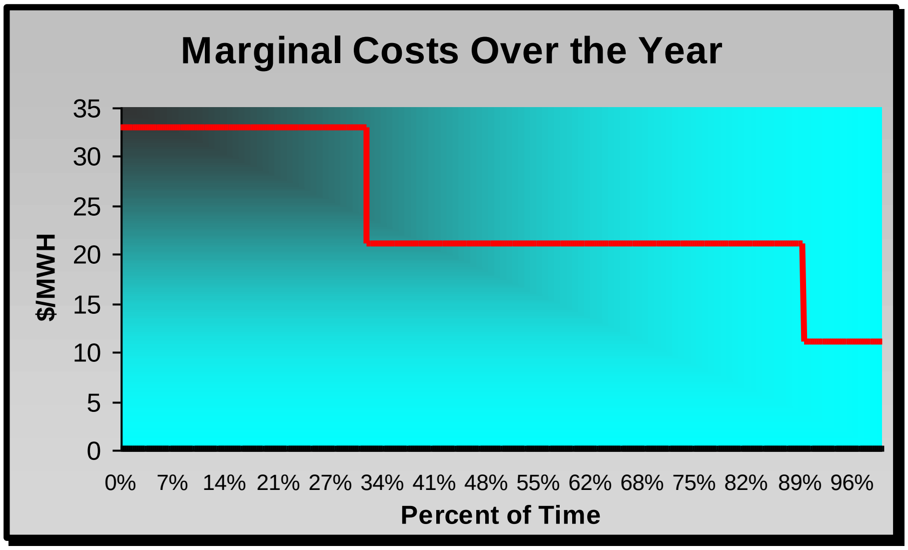
Value of Energy =
$\sum_{\text{Hours}}$ Max(Market Price of Energy $_{\text{Hour}}$ - Variable Cost of Energy $_{\text{Hour}}$)

Value of Capacity = Capacity Price – Fixed Cost

in equilibrium,

Value of Peaking Capacity =
Value of Combined Cycle Energy + Value of Combined Cycle = 0

The accompanying graph shows for how much of the year the three plants are on the margin. There are only three price levels on the graph because there are only three plants.



These equations mean that once the capacity mix is optimized, cost-based price of energy at different time periods and the cost-based price of capacity is also defined. The cost-based prices establish the value of different technologies. Therefore, long-run marginal cost in equilibrium can be computed from the load duration analysis and the analysis can be verified by assuring the net value of each new technology is zero. Section 1.3 of the workbook includes a simple model with a peaking plant, a combined cycle plant and a coal plant. The model computes market prices using a load duration curve relative to the minimum of available energy costs of technology in the market. The capacity mix is varied until the net value of different types of capacity is the same.

The tables and graph below present summary inputs and outputs of the long-run marginal cost model. This model can be used to test the effect how changes in variables affect long-run price outlooks. For example, if the capital recovery rate increases or the price of natural gas declines, the mix of coal declines. If the heat rate on combined cycle plants improve or if the capital cost of the coal plant increases, the mix of gas plants increase. These changes in the capacity mix affect the amount of time plants are on the margin and the marginal cost of energy.

Summary of Outputs of Equilibrium Model

Average On-Peak Interruptible Energy Cost	$ 28.78	per MWH	All-in Price at Capacity Factor of	100.0%	$ 29.29	per MWH
Average Off-Peak Interruptible Energy Cost	$ 18.93	per MWH	All-in Price at Capacity Factor of	75.00%	$ 32.11	per MWH
Average All Hours Interruptible Energy Cost	$ 23.84	per MWH	All-in Price at Capacity Factor of	50.00%	$ 36.40	per MWH
Capacity Price	$ 47.75	per kW/Year	All-in Price at Capacity Factor of	25.00%	$ 50.58	per MWH

	Capacity Percent	Energy Val per kW	Capacity Cost/kW	Net Capacity Value/kW	Capacity Value Deviation	Capacity Factor
Peakers	25.00%	$ -	$ 47.75	$ 47.75	$ 0.08	8.81%
Combined Cycle	25.00%	$ 30.59	$ 77.70	$ 47.11	$ 0.12	57.33%
Coal	50.00%	$ 101.22	$ 148.75	$ 47.53	$ 0.00	89.39%
Average				$ 47.47	$ 0.21	

	Capacity MW	Energy Generation	Energy Value	Fuel Cost per MWH	Generation Percent	Capacity Cost	Net Value
Peakers	5,637	4,348,207	$ -	$ 33.00	3.85%		
Comb Cycle	5,637	28,310,215	$ 172,418	$ 21.00	25.07%	168,835	3,583
Coal	10,250	80,258,696	$1,037,430	$ 11.00	71.08%	$ 1,035,200	2,230

Transition from Current Levels to Equilibrium Levels

The rate at which market clearing prices evolve from current conditions characterized by excess or deficient baseload or peaking capacity, to equilibrium pricing levels depends on a number of factors. With the current market prices –point A -- and the equilibrium market prices – point C, we have a lot of information. The question is how prices will move from point A to point C. The movement of prices depends on construction of merchant capacity, retirement of existing capacity, changes in productivity, load growth, movements in fuel price and many other factors. The more complicated models developed in subsequent chapters measures how prices can change.

Current market prices and marginal costs (computed from system lambdas) are presented in Chapter 2 for various different markets. The data sources for finding market prices and marginal costs are documented there. The economic derivation of energy prices that is the basis for current market prices is described in Chapter 3 and Chapter 8. Capacity prices are covered in Chapter 4.

We now have a lot of the building blocks to move ahead to analysis of risk associated with market prices and how to apply concepts of congestion pricing to market forward price projections. Applying the risk analysis to the prices described above involves option pricing models, Monte Carlo analysis and project finance modeling.

Marginal Cost and Prices Behavior in Different Periods

END

Economic Analysis of Interruptible Rates

Applications of congestion pricing range from paying less for an airline ticket through being a stand-by customer at an airline counter to purchasing tickets to a sporting event from scalpers to accepting the chance that your electric supply will be interrupted. The interruptible customer is willing to accept the chance that he may not be able to get on an airplane, that he may not be able to get into the sports

stadium or that he may not be able to receive electricity. If you are traveling as a standby customer, you either are allowed on the plane or you are not allowed on the plane depending on the capacity status of the flight. If you purchase interruptible power, you either receive power during a constrained time period or you don't depending on the demand and supply of power.

Working through the economics of interruptible electricity addresses the relationship between costs of constructing new capacity, the cost of new capacity and the equilibrium optimal amount of capacity that should be present in a market. The price discounts that are required for interrupted power can be also be used to explain price spikes that occur during high demand periods in competitive markets. Periods of interruption are those in which capacity is fully utilized without a price incentive for customers to reduce their usage. The exercise of determining equilibrium interruptible rates is a practical application of congestion pricing. Some of the implications of computing required capacity from interruptible rates include:

(1) The economic level of capacity in a market is driven by the marginal opportunity cost that consumers experience during power interruptions relative to the incremental cost of building new peaking capacity.

(2) The level of market capacity is driven to a significant degree by the demand responsiveness of customers with respect to their willingness to accept demand reductions at different prices.

(3) The cost of constructing new capacity – the supply side of the interruptible rate analysis -- is driven in large part by the carrying charge applied to the construction cost of the plants.

(4) The economic analysis of interruptible rates is most relevant through adding uncertainty to the analysis with respect to the probable number of interrupted hours.

(5) The number of interrupted or reliable hours in the analysis can be used to evaluate the implicit assumptions in more traditional reserve margin and loss of load probability criteria.

Assumptions and Definitions

In constructing the economic analysis of interruptible rates, the first step is to establish demand and supply schedules of how quantity supplied and demanded would change at different prices. Once supply and demand schedules established, equilibrium price and quantity can be determined. Defining the units of measurement for quantity and the price as well as the drivers of demand and supply at the outset clarifies the analysis and allows interruptible rates to be evaluated by simple review of a graph. To begin, assume that the analysis deals with a fixed amount of power at with varying amounts of interrupted different hours in an annual period. For example, say the amount of power is one megawatt. The analysis would then address how many interruptible hours would occur in a year and what the interruptible rate would be to result in the equilibrium interruptible hours. The fixed amount of power (i.e., one megawatt) can be assumed because there are only two groups and two products during congested periods, those who do receive power and those who do not receive power. The "product" and the price discount for interruption is the same for the first megawatt as it is for the thousandth megawatt in a particular hour.

Units of Supply, Demand and Price

There are two products that are implicitly purchased by consumers during congested periods, either recipt of power or interruption. The price of reliable power is the price difference for the two products -- the price discount for being willing to be in the group of customers who get interrupted is the same as a premium price for assuring that reliable power will be delivered during the constrained times. Since quantity is expressed in number of hours during constrained periods, price can be expressed in dollars per hour ($/MWH). Pricing on an hourly basis contrasts with the manner in which discounts for interruption are generally expressed in utility tariffs, where price discounts are measured in dollars per kW per month. However, if the number of hours of interruption were known, the price in dollars per kW per month could simply be divided by the expected number of interruption hours to restate the price in terms of dollars per

kWh or dollars per MWH. For example, if the interruption discount is $15/kW/Month and there are 5 expected hours of interruption, the price is $3/kWh – 15 dollars divided by 5 hours multiplied -- or $3,000/MWH if kilowatts are converted to megawatts. This type of conversion of prices expressed in monthly or annual units ($/kW/Year or $/kW/Month) to prices expressed on an hourly basis ($/MWH) are often made throughout the book and in the electricity generation industry.

The quantity scale for supply -- expressed as the number of hours in a specified time period for the defined amount of power – could be expressed as either interrupted hours or reliable hours. If interrupted hours are used in presenting demand and supply, the item being purchased – interruptible power – has negative value. Using reliable hours, the quantity is equivalent to the total number of hours in a period less the hours of interruption. I use interrupted hours as the quantity definition below because the number of outage hours can be equated to measures such as reserve margin and loss of load probability.

The Demand for Reliable Power

The demand schedule for reliable power measures the amount that customers are willing to pay under different expected levels of outage hours. For example, if there were only one hour of expected outage – because a relatively high level of capacity currently exits -- the amount customers would pay to avoid the single hour of outage may relatively small. In this case, many residences and businesses could incur on hour outage with a relatively small disruptions in business activity or lifestyle. However, as the expected number of interruption hours increase, the amount that customers would be willing to pay to incur the outage will likely increase.

If units of price on the vertical axis of a graph are expressed as price per MWH and the horizontal axis measures the quantity in terms of the number of reliable hours than the demand curve has a traditional downward slope. The greater the amount of reliable hours, the less one would pay in $/MWH to avoid an outage. If the number outage hours requires that business will be interrupted for half of the hours in a month, the price discount for accepting interruption would have to be very high. In terms of a formula, demand for reliable power can be represented as:

Demand for Reliable Power = Constant + Price Elasticity x Price of Reliable Power

In the above formula, the higher the price of obtaining reliable power, all else equal, the lower the quantity demanded. The above equation is difficult to estimate using regression analysis because of the lack of data. However, survey data developed in the industry and discussed in Chapter 4 suggest that customers will pay anywhere from $100/MWH to $10,000/MWH to avoid an additional hour of outage depending on the type of customer. For the equilibrium analysis below, I assume that if only one hour of outage occurs in a year, the price is $100/MWH while if 20 hours of interruption, the price increases to $10,000/MWH.

In supply and demand analysis, the demand and supply could be of a single customer of for an entire market. Our analysis is of an entire market and we are establishing the total amount of capacity required in a market. Therefore, the demand schedule considers the average amount of firm power for all customers in a market rather than a single individual customer. The market demand curve sums the quantity demanded across many individual customers at different prices. Therefore, even if a single customer had an inelastic demand curve that does not vary with the price, once different customers are summed across the quantity axis, the market demand curve will still have a downward slope.

The Supply of Reliable Power

On the supply side of the interruptible rate analysis, the marginal cost of providing reliable power can be defined as the minimum cost method of providing reliable capacity during congested periods. The amount of hours during a year that congestion is expected to occur should be relatively small. Therefore, the variable costs of running a plant are not very high relative to the recovery of capital cost. This means it is reasonable to approximate the supply curve for reliable hours with the cost of a peaking plant such as a combustion turbine facility.

To illustrate the supply curve for reliable power, assume that the costs are being expressed in terms of dollars per MWH. Further assume that the quantity is expressed in reliable hours per year. For example, the cost to supply one additional reliable hour in a year measured on a dollars per MWH basis is the total carrying charge of a plant per MW for the year plus the fixed operating costs divided the one hour of operation. The fuel and variable costs for operating the plant for that hour must be added to the fixed cost. The cost of providing supply to provide two added hours of reliable supply is the fixed cost divided by two rather than one hour, plus the variable costs. In terms of a formula, the supply curve can be represented as:

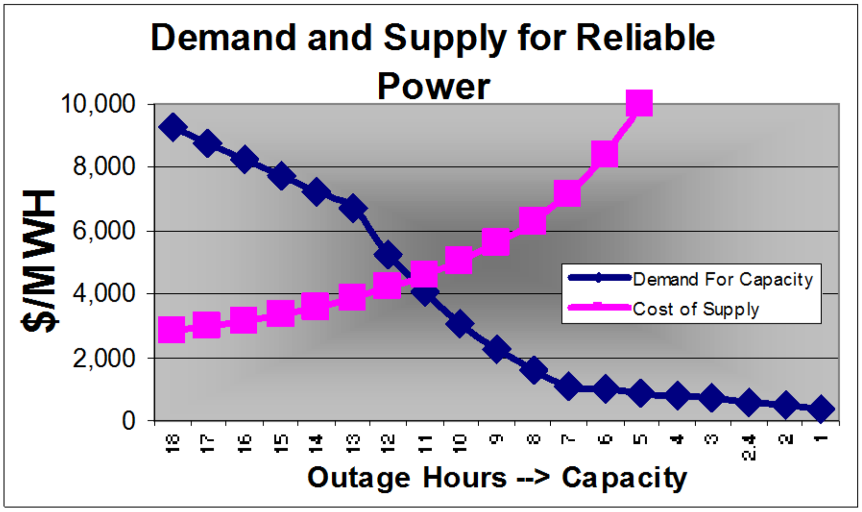
Cost of Supply per MWH =
(Capital Recovery + Fixed O&M)/Expected Hours +
Variable O&M/MWH +
Fuel Cost per MWH.

Through making some relatively simple assumptions, the supply curve can be illustrated. Assume the cost of a peaking plant is $350/kW, the heat rate is 11,000 BTU/kWh, the fuel cost is $2.75/MMBtu, the variable O&M cost is $3/MWH and the fixed operation and maintenance cost is $5/kW/Year. The capital cost of $350/kW/year is converted to an annual number using an economic capital recovery rate adjusted for inflation and economic oblescence of 11.4%. (The section below describes issues associated with real carrying charges.) The annual capital cost is $350 multiplied by 11.4% or $40/kW/Year. If there are 20 hours of interruption in a year, this capital cost is equivalent to $2,000/MWH ($40/kW/Year x 1,000/20.) This is far higher than the variable costs – fuel and variable O&M -- of $33.25/MWH. Including the fixed operation and maintenance cost, the total supply cost is $2,283/MWH.[19] If the hours of interruption increase to 40, the supply cost per hour declines to $1,158/MWH. This simple example demonstrates how costs change significantly as the number of reliable hours change.

Equilibrium Analysis

The illustrative example above uses the demand and supply schedules to establish an equilibrium price. The hypothetical analysis below suggests that in equilibrium, the number of outage hours in the market is about 11 hours, and the price for firm power is about $4,000 per MWH. The sensitivity of these numbers to demand and cost drivers depends on the shape of the demand curve. For example, if the cost of a peaking plant changes, this shifts the supply curve and means a different market clearing level of capacity is implied. In terms of demand, if the effective price for interruptible power is set too high or too low, there will be a surplus or deficit in capacity relative to the optimum level.

[19] The calculation involves multiplying the $350/kW by 1000 to translate the figures into megawatts and then multiplying the product by the carrying charge rate of 11.4%. This number of $40,000 divided by 20 hours produces the figure of $2,000/MWH. To this, the fixed cost of $5/kW is added which translates to a cost of $250/MWH (5 x 1000/20.) The variable costs are computed as the heat rate of 11,000 multiplied by the fuel cost of $2.75 to yield a fuel expense per MWH of $30.25/MWH. Adding the variable O&M of $3/MWH yields a total cost of $33.25/MWH.



Once the supply cost and the demand schedules for reliable power are established, we are ready to evaluate the equilibrium quantity of capacity and the equilibrium price. The market clearing level of interrupted hours in this analysis can then be translated into total capacity in the market because the interruptible hours are part of the loss of load probability formula. Loss of load probability can be defined as the interruption hours divided by the total hours. The greater the amount of capacity the lower the number of hours of interruption. After translation of interruption hours to capacity, the analysis of interruptible rates can be used to evaluate traditional reliability criteria such as a one day in ten year loss of load probability and/or a 15% reserve margin.

Interruptible Rate Analysis and Equilibrium Capacity

The interruptible analysis has a number of implications that are central to the economics of electric power. First, the simple hypothetical example shows how prices can reach very high levels in congested periods. Second, the demand response of customers must be considered in developing equilibrium rates. Third, administrative criteria such as a reserve margin or a loss of load probability are not relevant to analysis of competitive markets. Fourth, since the number of reliable hours is a stochastic rather than a deterministic variable (i.e. it is random and cannot be known with certainty), variability and volatility significantly impacts capacity expansion and electricity economics. These are all subjects of later chapters.

The economic analysis of interruptible rates can be used to evaluate the impacts of traditional administrative rules that capacity should be constructed to meet a "one day in ten years loss of load criteria." Because there are 24 hours in a day, the one day in ten years is equivalent to an outage rate of 2.4 hours per year. Given the cost of constructing peaking capacity, the implied price per MWH for reliable hours can be determined. Using the cost assumptions discussed above for a combustion turbine, this results in the following formula:

Implied Price/MWH = (Fixed Cost)/2.4 Hours + Variable Cost

The fixed cost is $13,958/MWh for 2.4 hours and the variable cost is $39/MWH, implying a total cost of $13,996/MWh. This means if one believes the one day in ten rule is an appropriate reliability criteria, we believe the value of power during 2.4 hours of outage is about $14,000/MWH. The $1,000/MWh price spikes don't seem so high in this context.

This analysis addresses a central issue relating to whether or not competitively determined prices can reach equilibrium and at the same time produce a reliable electric system. Some argue that competitive prices cannot result in an adequate level of reliability for a crucial service such as electricity and that competition on the wholesale level has in fact primarily been a matter of "free-riding" on reliability. There are reasonable issues regarding whether metering technology can differentiate customers in the

interrupted group from customer in the reliable supply group. Further, some can argue that no level of interruption is acceptable for a service as essential as electricity. If prices must be regulated to ensure reliability, then discussion of allowing markets to operate to produce optimal investment and customer benefits cannot be serious. As soon as regulation is introduced into a portion of the system, distortions in the market occur. Therefore, the analysis of whether a price can be established for reliability – through interruptible rates – is important to the remainder of the text.

Appendix 1: Review of Electricity Price Trends

Energy prices in general and electricity prices in particular are used to describe some of various concepts in this chapter because they are more volatile than prices in most other segment of the economy. Because energy prices fluctuate so much more than those of other goods and services that the "headline" consumer price index reported in the press often excludes changes in energy prices. Volatility caused by oil price shocks of the 1970's caused worldwide economic turmoil and prompted policy makers to develop mechanisms that protect investors from price fluctuations (fluctuations are illustrated on the graph below[20]). While modeling electricity generation prices is the focus of discussion in this chapter, economic statistical and financial concepts used to develop mathematical equations for electricity are equally pertinent to prices of many other goods and services. The formulas for volatility and mean reversion are the same in analysis of natural gas, oil, copper, pulp and paper, palm oil, real estate and even computer chips. Discussion of how one should temper application of mathematical formulas with judgment derived economic analysis is as relevant to other commodities as it is to electricity.[21]

To study the movement of any type of commodity price, you should begin by gathering data on trends and fluctuations in historic prices. For electricity generation, the lack of storage means that inventory cannot be used to moderate the effect of demand movements on price from one period to the next (the lack of storage for electricity would be tantamount to a grocery store having to have just the right amount of milk to meet the demand of each customer coming into the store at each instant). Because of the lack of storage, observed price trends differ markedly according to how prices are compiled by time period – the historic patterns are very different if one reviews average annual price data than if one graphs hourly data. Therefore, in examining electricity prices for purposes of developing mathematical models, the discussion of historic data is separated into investigation of annual, monthly, daily and hourly trends.

As a prelude to review of market prices and development of mathematical models, one should consider what electricity prices should look like when the analytical process is finished. Three basic characteristics of market prices for electricity that have been summarized by Graydon Barz and Blake Johnson[22]:

1) Mean reversion of prices both in the short and long term, which is due to the fact that the supply curve defined by generating plant costs remains relatively stable over time (it takes a long time to build new plants);

2) Generally smooth price changes from one time period to the next driven by smoothly fluctuating demand, punctuated by infrequent and temporary but dramatic upward price "spikes" which occur because of the high cost of supply shortages (electricity outages are very expensive to customers); and,

[20] Data for various price series can be found at the survey of current business website, www.eia,gov. Energy price data can be obtained from the Energy Information Agency website, www.eia.doe.gov and the international energy agency website, www.iaea.org.

[21] http://data.bls.gov/PDQ/servlet/SurveyOutputServlet

[22] "Modeling the Price of Commodities that are Costly to Store: the Case of Electricity", Graydon Barz and Blake Johnson of Stanford University. Published in proceedings on energy risk management.

3) Daily, weekly and seasonal correlation between price level and price volatility – implying that there is more variation in prices during periods of high price than during low price periods (due to the non-linear shape of the supply curve).

After developing forward price models in this and the next few chapters, the picture of electricity prices that comes out of the analysis should be consistent with these three elements. Conversely, if results from the modeling process do have these three characteristics we should be suspicious of the models.

In addition to the output of models reflecting the above three characteristics, the input parameters in mathematical models should be in line with underlying economic factors that cause prices to move. This implies that one should understand what economic factors cause parameters to be relatively high or low even though the time series are generally computed directly from historic price data. Using an example from another industry, if one were forecasting the price for transporting bulk commodities with ocean carriers, the mean reversion parameter computed from the data should be consistent with the speed at which new ships can be built and old ships are disposed in response to demand changes.

The manner in which some of the underlying drivers of electricity price movements affect times series parameters include:

- The volatility parameter for electricity price models is driven by variation in loads (which are in turn caused by variation in weather and economic activity); volatility in hydro conditions; fluctuation in fuel prices; unexpected changes in the capacity added by new suppliers; and variation in the productivity of new technologies.

- Mean reversion in electricity prices comes about because weather comes back to normal levels over time, water flows in rivers (hydro conditions) revert to long-run average levels, primary fuel prices for oil, gas, coal and other fuels exhibit mean reversion and developers of new plants react to over-supply ore under-supply conditions in the market.

- Long-term trend parameters in electricity price time series equations are influenced by changes in productivity of new and existing supply including trends in fuel prices; changes in environmental cost; variations in the productivity and the real cost of constructing new plants; and, differences in the way consumers use electricity.

- Lower and upper bounds on prices in the mathematical models are driven by short-term marginal costs of suppliers and consumers – prices do move below short-run marginal cost because suppliers will stop producing and prices should move above the short-term value to consumers because then consumers will reduce their demand.

Price trends for differing time periods – trends in average annual prices, average monthly prices, average daily prices, or individual hourly prices – are relevant for alternative investment decisions. For example, in order to assess an investment in a new run of river hydro generating plant, the trend in annual prices and the volatility of prices around the long-run expected trend is the most important consideration in evaluating risks and profitability of the investment. Since the hydro plant's operation is independent of the electricity price (it dispatches as the river flows), patterns of hourly, daily or monthly prices are not less important than the average level of annual prices over the expected life of the hydro facility. In contrast to the hydro plant, consider a hypothetical decision of whether to sign one of two year purchase contracts. The first contract has relatively high energy prices and low capacity prices while the second has lower energy prices and higher capacity prices. For this decision, it is necessary to understand the time pattern of prices within a year such as monthly average prices because the risks of fluctuating prices can be moderated through paying a higher capacity price. Finally, think about the decision to retire a peaking plant that is currently operating only a few hours in a year. To evaluate this disinvestment decision, one must understand hourly movements in price whereas the overall annual averages are largely irrelevant for the decision.

In reviewing historic prices, data is presented for various different markets with different characteristics in different areas of the world. The markets include the PJM region, the NEEPOL system and California market in the US and national prices for the UK, Argentina and South Korea. Given the importance of alternative price durations for various decisions, trends in annual, monthly, daily and hourly prices are reviewed below. Data sources that are available and used in the historic analysis are described in Appendix 1 to this chapter. The historic price data itself is included in section 2 of the workbook.

Annual Price Trends

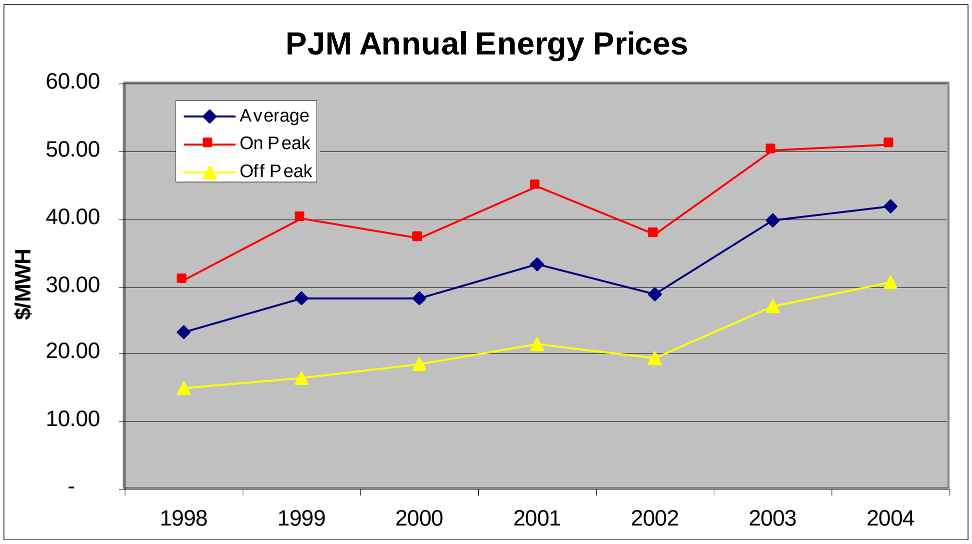
Investments made in an electricity generating plants are often expected to last for three decades or more. When making such long term investments, one would like to know the general upward or downward movement in prices over an extended future period as well as the potential volatility around the long-term trend. Because of the mean reversion in electricity prices related to weather, water flows and other factors, short term price analysis is less important for long-term investments since swings in monthly, daily or hourly prices tend to balance each other out over the years. The most relevant historic data in assessing the reasonableness of a long-term forecast is an extended series of annual prices.

One problem with evaluating annual average prices for electricity is that a limited history of market determined prices is available because of the relatively young age of deregulation. Some of the markets that implemented competition relatively early include the UK pool, the Argentina pool and selected markets in the US. The limited annual price data does illustrate how trends in long-run prices are driven by factors that include the level of capacity additions; the pricing of primary fuel; changes in plant efficiency; demand growth; and changes in the structure of the market. When making a forecast, one must account for these factors either implicitly in parameter estimates or through explicit adjustments to a model. It can be argued that making naïve forecasts from historic price data without accounting for structural changes in markets has caused tens of billions of dollars of losses in the merchant power business.[23]

The first graph below illustrates trends in average annual energy prices for the PJM market since prices where initially established using a competitive bid process in 1998. The PJM region originally covered the US states of Pennsylvania, New Jersey and Maryland and has expanded into Ohio, Illinois and other States. The region has limited hydro capacity and the peak load occurs during the summer season. Many analysts believe the design of PJM pool in terms of the way prices for day ahead power are published, the manner in which installed capacity markets have been implemented and the establishment of locational marginal prices is an effective structure as compared to other market designs. (Effects of capacity market structures on energy prices is discussed at length in Chapter 4.) The graph of annual average prices presents both on-peak and off-peak energy prices and reflects real time rather than day-ahead prices.[24]

[23] Ibid. .

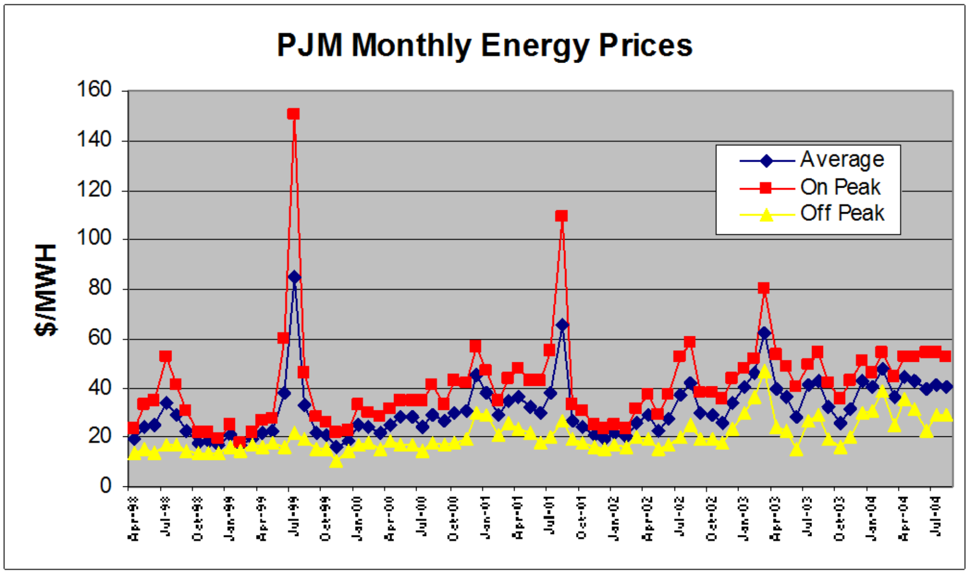
[24] Power markets often use on-peak and off-peak categories in making trades because prices have different traits in the two time periods. The peak time is generally defined to be 16 hours beginning at 7:00 AM and ending at 11:00 PM during weekdays. Because of this definition of on-peak periods, the units of power bought and sold in the market are often referred to as 5 x 16 blocks (5 weekdays multiplied by 16 on-peak hours per day).



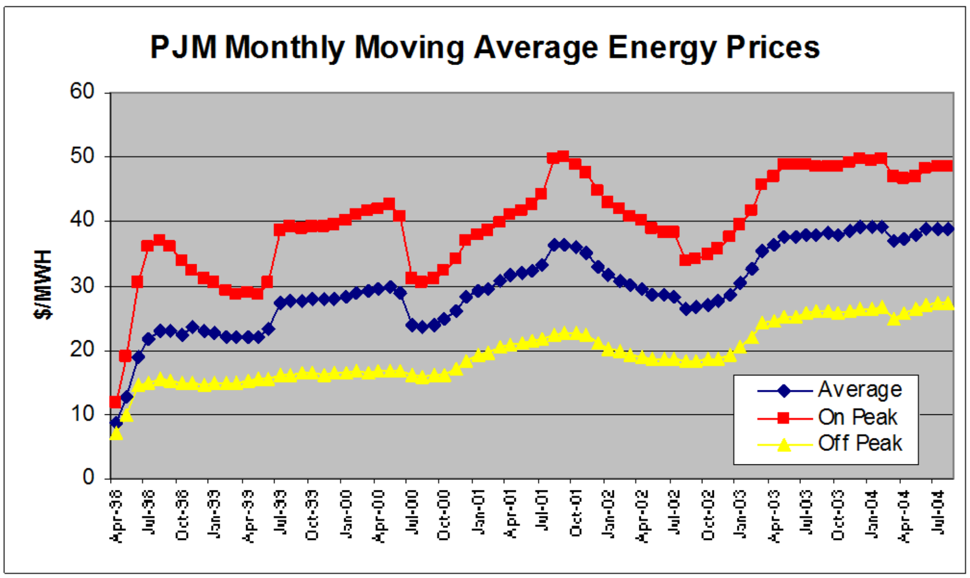
In the above graph, the increase in PJM prices that occurred from 1998 to 1999 was primarily the result of supply shortages. The decrease from 2001 to 2002 was in large part due to demand decreases and new capacity additions that came on line in the region. High price levels in 2003 and 2004 were driven in large measure from increases in the price of natural gas and oil. While swings of $10/MWH that occurred in various years represents more than a 20% change in price, the annual price data for PJM energy prices is not as volatile as other commodities such as oil and gas shown in the graph that introduces the chapter. The annual average prices for PJM also demonstrate that off-peak prices were not influenced much by the capacity and demand changes.

Monthly Price Trends

Monthly price trends shed light on aspects of electricity prices that are not revealed in the annual average price data. To evaluate monthly price trends, additional graphs are presented for the PJM market and average monthly prices are presented for the South Korean market. Trends in monthly average prices, trends in twelve month moving prices and average monthly prices are reviewed. While the absolute level of prices is presented, prices relative to fuel costs known as spark spreads may me more important to the value of plants than the absolute level of prices. For example, the high monthly prices driven by the price of natural gas may be very favorable for coal or hydro plants, but not for combined cycle plants.

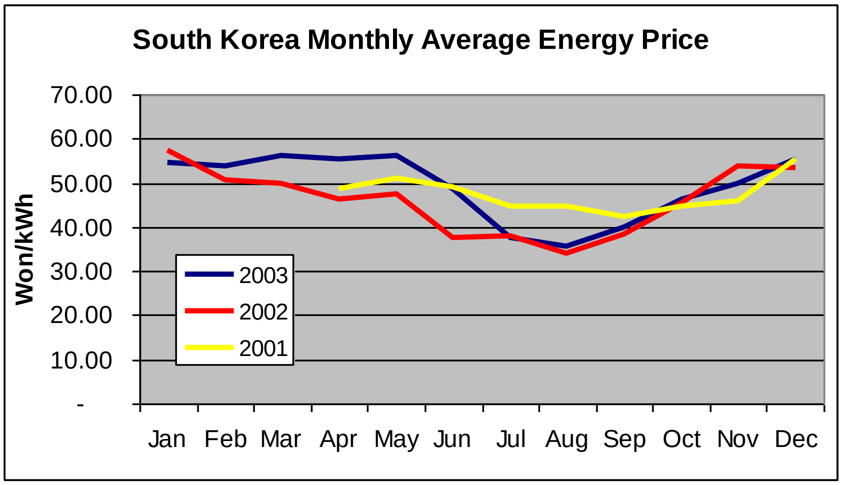


The monthly PJM prices in the above graph illustrate how prices in 1999 and 2001 were driven by very high prices in the summer period while the prices in 2003-2004 have been higher for virtually all months. The summer time price spikes have been less pronounced after 2001 because of capacity additions in the eastern region of the US. Off-peak prices did not exhibit summer price spikes in 1999 and 2001 but have followed the general upward trend in fuel price driven increases that has occurred in 2003 and 2004. A predominant feature of the monthly average prices other than the price spikes is the high degree of mean reversion. The graph demonstrates that off-peak prices have a lower boundary.



The twelve month moving average in the above graph shows price levels experienced by consumers and producers that are difficult to discern from monthly average prices. The graph demonstrates that the differential between on-peak and off-peak prices is more than $20/MWH and it demonstrates the average annual bill was strongly influenced by the level of price spikes. The graph illustrates that because of the price spikes, mean reversion and influence of fuel prices, the manner in which prices are presented (such as spark spreads discussed later on) has a significant effect on the information that is conveyed.

Without price spikes, the question arises as to whether prices are generally higher in the summer time when loads increase from air conditioning, whether prices are higher during months in which generating plants are down for scheduled maintenance or whether prices are higher during the winter in which loads are higher for extended periods of time. To review these issues, we present energy prices for the South Korean power pool. This pool is cost-based with separate capacity prices as in Argentina and it was established in 2001. South Korea is a dual peaking system where the summer peak is about the same as the winter peak and loads are much more level than those in the US or the UK. The system consists primarily of nuclear, imported coal and LNG capacity and there is surplus capacity in the country.

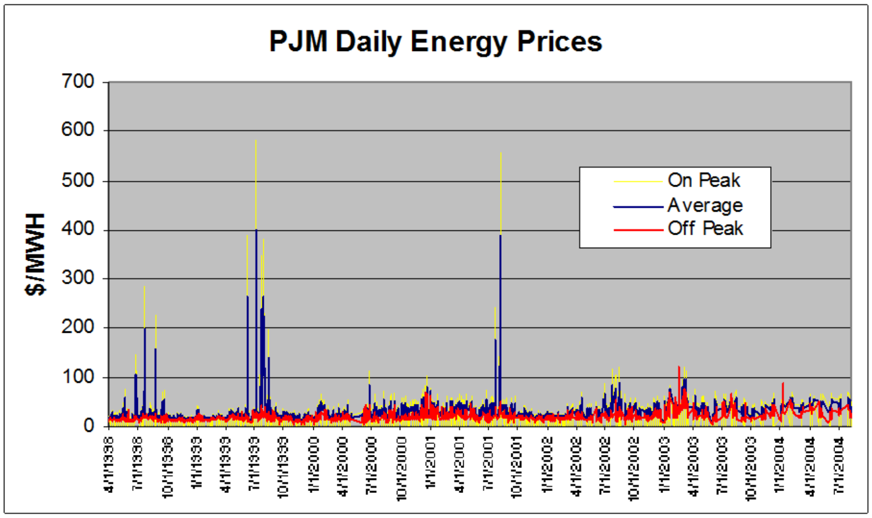


The South Korea monthly average prices demonstrate that prices are low in the summer months when little or no capacity is out of service for scheduled maintenance. Prices are relatively high in the months of March, April and May when loads are low but plants are out of service. Prices are also high in the winter months when capacity is available, but the loads remain high throughout the day.

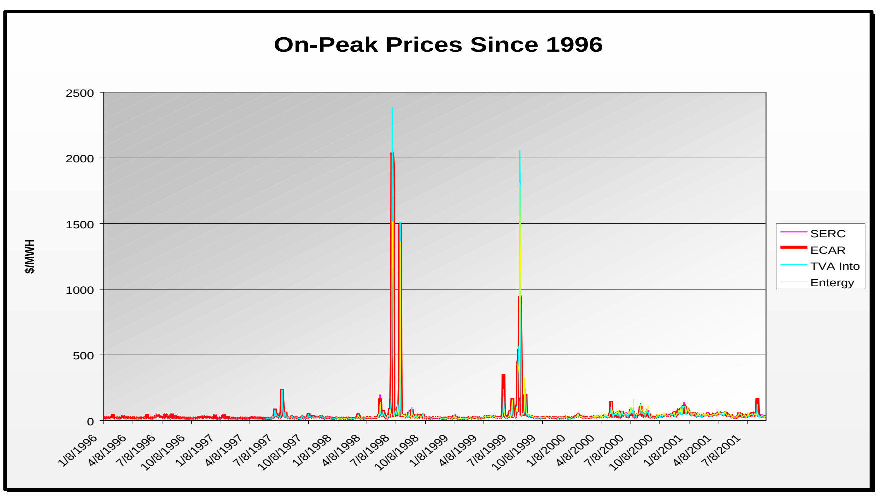
Daily Prices

Daily average prices provide insight into economic factors that drive the movement of electricity prices which are not obvious in either the monthly average or the annual average series. Daily average prices are important for some market participants because daily prices are often the basis for transactions (for example, 1x16 blocks) and daily averages are often published as price indices. Two graphs of daily average prices are presented below for various market regions of the US which illustrate both patterns in prices and the differentials in daily prices caused by transmission constraints.

The first graph presents average on-peak, off-peak and 24-hour prices for the PJM region. The graph demonstrates that the reason monthly price spikes occurred in the above graphs resulted from a few daily price spikes rather than prices that were high for an entire month. Further, the price spikes have been exclusively concentrated during on-peak periods. Since 2001, there were no periods in which prices exceeded $100/MWH by a significant margin suggesting that an adequate amount of capacity was bid into the market. As with the monthly price data, average daily prices exhibit a high degree of mean reversion where price increases are followed by price declines.



The second graph of daily average prices presents on-peak prices for vast regions in the middle of US in an area ranging from Detroit to Arkansas. These prices are published in trade presses for bilateral transactions rather than being established by bidding into power pools. (The prices are surveys of "marketer firm" power which means there is a commitment to deliver the hourly energy and significant financial penalties occur if the power cannot be received by the purchaser for the hour in question.) In general, daily average prices for bilateral transactions exhibit similar general patterns as the above PJM graph with a high degree of mean reversion and extreme price spikes. By presenting more than one region, effects of transmission constraints can be evaluated. Divergent prices across regions would suggest the presence of transmission constraints either in the form of physical limitations on the ability to transmit power or economic limitations on making transactions driven by transmission prices. The graph demonstrates that prices across regions have been highly correlated even during price spike periods. The data suggests that physical transmission constraints and transmission prices have not had a large effect on prices in these regions (transmission issues are discussed extensively in Chapter 8).

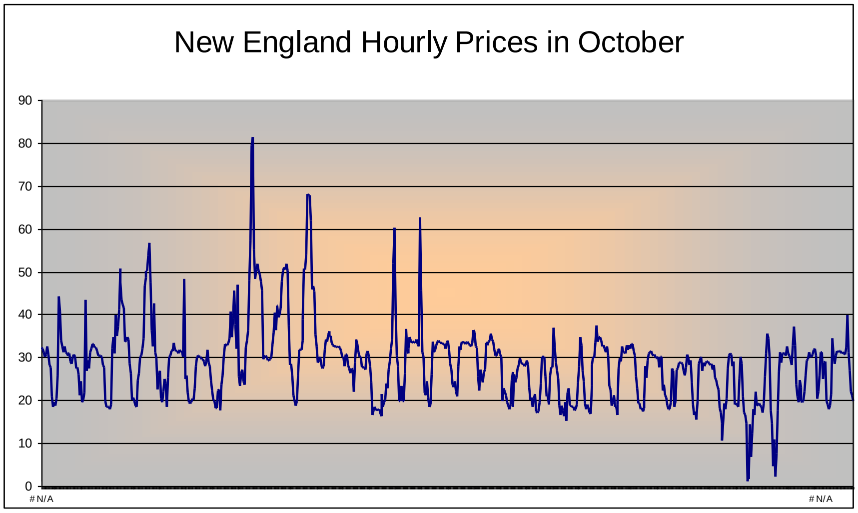


Hourly Prices

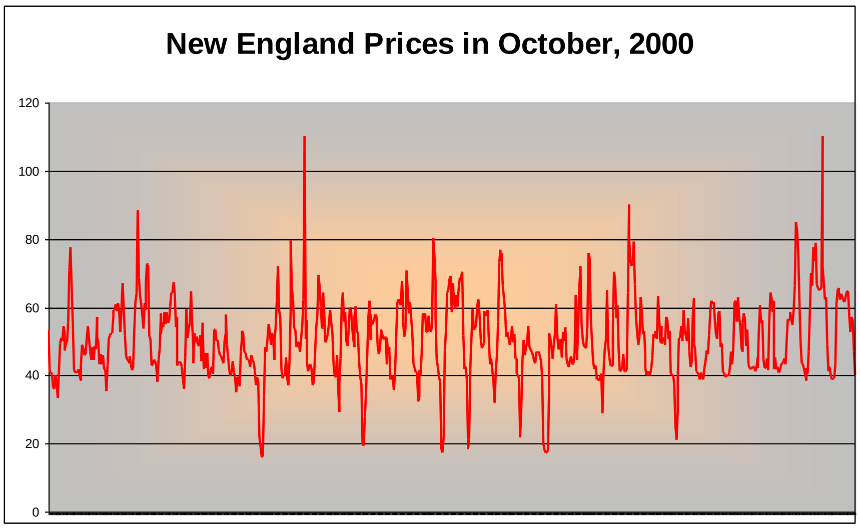
While the average daily and average monthly prices demonstrate the mean reversion and spike tendencies of electricity prices, the annual, monthly and daily data masks price boundaries and daily volatility of price driven by daily demand patterns. To investigate price boundaries and price patterns

within a day, hourly prices are presented for selected months for the Northeast region of the US (in the NEPOOL market). Prices are shown for summer months in which there were no price spikes as well as summer months in which price spikes occurred. In addition, graphs of hourly prices are shown for Autumn months with relatively low load periods.

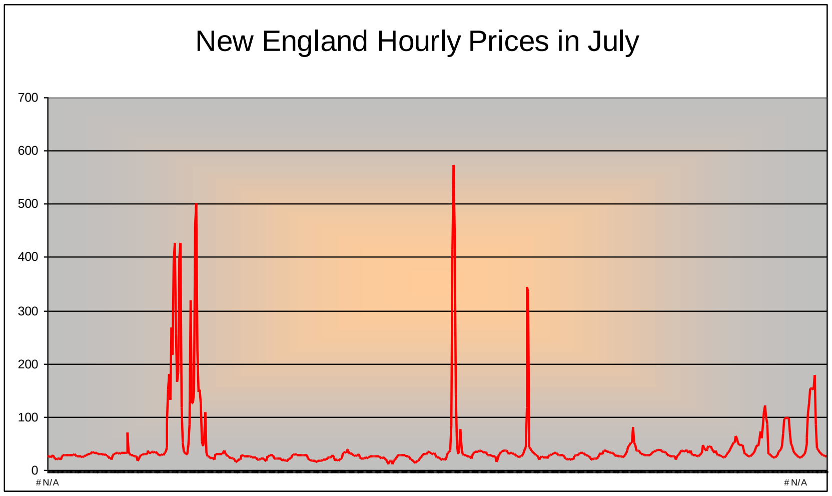
In later chapters, price levels will be modeled in much shorter time periods than monthly increments. Therefore, it is instructive to review historic price movements in hourly increments. In areas where market-clearing prices are traded in power pools such as in Australia, Great Britain, New England, PJM, New York and California, hourly data on prices is generally available. I have used October prices in New England to demonstrate how hourly prices move during non-summer months. Note that the prices in 1999 during the course of a day generally moved up by about $10/MWH relative to their low value. In some days the prices reached very low levels and the high price for the month of October 1999 was about $80/MWH.



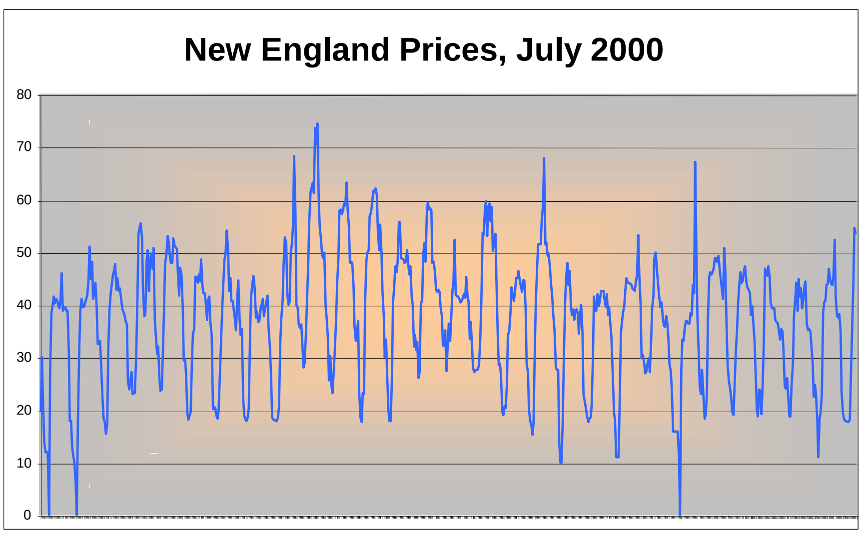
In October of 2000, the prices had the same kind of pattern, but the price levels were significantly higher. The reason for the higher prices was in large part due to the fact that prices of natural gas and residual fuel more than doubled from 1999 to 2000. Comparison of 1999 and 2000 demonstrates the importance of the price of "primary fuels" on the level of market clearing prices.



The review of prices in the Southeastern U.S. already has demonstrated that prices behave very differently in the summer time period as compared with the non-summer time period. The graph below illustrates the different characteristics of summer prices through plotting the prices for July 1999 in New England.



Unlike the prices in October, the graph of July prices is dominated by a few days in which prices reached extreme levels. In 1999, July prices reached the $500/MWH level for a number of hours while in other hours the prices were in the $20-$40/MWH range. On the other hand, in 2000, the prices did not "spike" to the extremely high levels.



The analysis of prices in the summer months illustrates the impact of weather combined with plant outages on price levels. In 1999 the month of July was relatively hot and some of the plants in New England were not operating (the Milestone 3 nuclear plant). On the other hand, in 2000, the weather was relatively mild and all of the nuclear units were on line.

Chapter 5 Appendix
Computation of Carrying Charges with Technological Obsolescence

The practical application of changing productivity levels to electricity generating plants can be accomplished by applying the six step procedure described below. This procedure converts real productivity changes into an annual percentage and subtracts these percentages form the expected inflation rate.

1. Compute cash flows from earning a level dollar amount in each year.

2. Estimate the decline in energy value in each year resulting from changes in the technical efficiency of new plants and the expected change in the real capital cost of the plant.[25]

3. Convert the declines in energy value into percentages of the capital cost through dividing the change in (real) energy value by the capital cost of the plant.

4. Compute the expected changes in the real cost of new plants as a percent of the initial cost of the plant in real terms.

5. Combine the percentage change in energy value and real capital cost to establish a year by year productivity factor change.

6. Apply the rate of decline in productivity against the inflation rate to establish a net nominal rate of change over the life of the asset.

Alternative approaches can be developed which simplify the process. One method is to use a plant life for carrying charge purposes that is shorter than the expected plant life. For example, if a plant is expected to last 35 years on an economic basis, but the carrying charge is computed on the basis of 20 or 25 years, the truncated life implicitly allows for obsolesce. Of course, when making these sorts of adjustments, I encourage the reader to compute the implied productivity increase that is incorporated in the calculation. That is to say, you should know that if the life is truncated by 10 years, by how much the productivity is expected to improve.

[25] See Chapter 3 and Chapter 6 for a description of energy value.

Overall Definition of Marginal Cost	Marginal cost is the amount of additional expenditure that would be necessary to provide an additional unit of a good or service. In the context of electricity, marginal cost can be more specifically defined according to the functions of generation, transmission and distribution.
Marginal Cost of Generation	Marginal cost of generation is the opportunity cost of economic resources – fuel, variable operation and maintenance costs as well as forgone "utility" during capacity shortages that results from consumption of electric energy (watt hours – kWh, MWh or GWh).
Marginal Cost of Transmission	Marginal cost of transmission is the cost of resources that are forgone by transmitting electricity – often it is near zero (the cost of line loss) because consumption does not necessitate building of new lines or limit otherwise economic transactions. However, the marginal cost of transmission can be high if transmission constraints prevent the occurrence of economic transactions for generation.
Marginal Cost of Distribution	Marginal cost of distribution is the cost of resources that must be incurred to expand the distribution system when new customers connect to a system and/or load increases.

APPENDIX – Construction of Supply Curve

The price can be determined using the following process:

Step 1: Add a variable that is set to 1.0 (true) when the demand is between two points on the supply curve and zero (false) otherwise.

Step 2: Use a look-up table with a test value of 1.0 to find the price at which the demand intersects supply.

Step 3: Loop through the process using different levels of demand using a macro that cycles through the Step 1 and Step 2.

The analysis of marginal cost principles in this chapter is consistent with a basic theme that continues throughout the book. In describing each of the market-based analytical models, some fundamental economic, financial, statistical and engineering theory that supports each model is described before the model is applied to real world situations. It is the need to integrate many business disciplines and capture the complexities of this market place that makes analysis of electricity generation both interesting and uniquely instructive. Consider for example the issue of projecting future "spikes" in the price of electricity. Effective modeling of price spikes requires an understanding of the economic supply and demand conditions that can cause such rapid price changes, options pricing models, capacity pricing and statistical analysis of price movement. With a foundation in these economic and finance principles, models that predict the level and frequency of price spikes can be better applied in practice.

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Analysis of prices determined in competitive markets should be equally relevant for managers in places where generation markets are not de-regulated. If electricity generation is subject to price regulation or owned by government agencies, managers can improve decision making by considering risk and value through modeling prices as if competitive market conditions were present. In regulated or state run systems without a market clearing price, simulation of marginal costs and market prices should drive investment decisions and risk assessment.

Many readers may want to move straight to more exotic subjects such modeling price behavior using time series equations (estimating volatility, mean reversion, price boundaries and other parameters), analyzing the effect of transmission constraints on forward prices, using option models to assess credit spread on project financed plants, and constructing volatility parameters from supply and demand models.

Without a solid foundation in the fundamental economic concepts, the fancy modern analytical approaches are difficult to follow and have less value in real world decision making.

Later on, in describing competitive market models, subjects such as how option theory applies to electricity prices, measurement of forward prices that incorporate the price spike behavior of electricity, and methods for using project finance models along with volatility in valuation of generating plants are addressed. When discussing these competitive market concepts with managers from privately owned and publicly owned electricity concerns around the world, I have found that a solid understanding of market-based analytical techniques to be an essential tool for investment analysis in either regulated or deregulated environments. This means that the economic principles related to marginal cost that drive pricing and asset valuation in competitive markets are as relevant to investment decisions made by a planner in a state owned utility company in Japan as to a power marketer in a working in the British de-regulated system.

In this situation, we as a society will all supposedly be better off because both resources will be allocated and used as efficiently as possible.

In addition, long-run marginal cost analysis is often used to assess whether retail rates are set at levels that provide an appropriate consumption incentive; long run marginal cost is used to determine whether significant market power is present; and long-run marginal cost can be used to test whether prices in long-term contracts are reasonable.

The theory that economic efficiency is maximized when prices are set to marginal cost is well known and not subject to debate in economics.

The chapter uses three exercises that work through practical issues in computing the long-run marginal cost of electricity:

- The first case exercise involves computation of short-run marginal cost through constructing supply curves and alternative levels of demand.
- The second case exercise demonstrates computation of carrying charges for spreading the costs of capital equipment over time which is a large component of long-run marginal cost.
- The third case shows how long-term equilibrium prices can be calculated through computing the optimal capacity level and the optimal capacity mix in a system.

To illustrate computation of marginal costs where only one type of technology exists, consider the example of electricity where only type of technology is a combustion turbine plant that uses natural gas and has a heat rate of 10,000 BTU/kWh (the heat rate is a measure of efficiency that converts units of fuel consumed – BTU – to units of electricity produced.) Further assume that there are only two demand periods. The demand in the unconstrained period – 8,660 hours of the year -- can be met with the combustion turbine not operating at full capacity. During the constrained period – the other 100 hours of the year – the plant runs at full capacity implying that not all of the demand can be met. For those periods when capacity is not constrained, the only marginal cost is the variable cost of operating the plant – its fuel and variable operation and maintenance. All capacity costs are recovered from much higher prices during the time periods plants when are operating at full capacity and customers the capacity must be rationed among customers. The toll bridge example and congestion price theory implies that prices should be high enough during the 100 congested hours to prompt some customers to reduce demand. If prices are not high enough to prompt lower demand, there will be people who cannot be served from the existing capacity. On the other hand, if prices are too high in constrained periods, customers will limit their usage and there will be unused capacity.

In the case of a single technology, marginal costs applicable to the two periods -- off-peak periods and constrained periods -- can be described with a few formulas. Assume the annualized cost of a combustion turbine plant is $40/kW/Year (the calculation of annualized costs and carrying charges are described below). Assume the fuel price is $3.50/MMBTU and the variable operating and maintenance cost is $3.00/MWH.[26] If capacity is allocated to the 100 high usage hours resulting in a price of $438 per MWH relative to a price of $38/MWH during un-congested periods, the equations do not solve the problem of defining how high prices must be to yield equilibrium levels of capacity. Perhaps the $438/MWH prompts customers to reduce their demand so much that there are no longer any constrained periods. In equilibrium, the demand elasticity of customers during peak periods determines the number of hours that the combustion turbine plant runs at full capacity. In equilibrium, the number of constrained hours is just enough so that the amount by which customers are willing to pay to not use electricity just equals the cost of added capacity in the constrained period.

[26] The capacity cost per MWH can also be computed from the load factor of the constrained period. In general, load factor is a statistic that measures the number in a sub-group divided by the total number available. In the context of airline seats, it is the number of seats used on a flight divided by the total available seats. For electricity generation, the load factor is the number of hours for which electricity is used divided by the total hours in a period. In our case, the load factor is the number of constrained hours (100 hours) divided by the total number of hours in the period -- 8,760. This implies the load factor is 1.142% and that the capacity cost can be computed as the cost of the combustion turbine unit --$4,000/MW – divided by 8,760 multiplied by the load factor.

Techniques for measuring future trends and dispersion in long-run marginal cost are highly dependent on the nature of markets in which the product is sold and the competitive structure of the industry in which the firm operates. In explaining marginal cost analysis, one option is to survey a variety of forecasting techniques at a surface level for many industries without delving into detailed forecasting issues. However, this approach does not illustrate the type of modeling that is behind forecast analysis in many actual investment analyses.

In the electricity industry, the market-clearing price of electricity is the centerpiece of valuation analyses for issues ranging from evaluation of purchased power contracts to assessing credit quality of merchant companies to the trading of electricity futures. It is difficult to think of significant decisions involving electricity generation system that do not depend on the future level of market clearing price. Appendix 1 reviews electricity in different markets and the sources for obtaining the data. Some of the markets have different structures than others in terms of how prices are calculated. For example, some markets are derived from confidential bids in each hour while others are derived from audited marginal costs. In some markets, components are added to the energy price to compensate for capacity costs and other factors. In virtually every market some kind of energy price is established from sorting the bids or costs of individual plants (or parts of plants) and finding the highest level of price that just meets demand. This sorting of costs or bids for different types of production defines the supply curve.

Supply curves which sort the cost of producing capacity can be computed for just about any industry where there are tradeoffs between fixed costs and variable costs. Similarly, the long-term cost of production derived from the lowest cost of building new capacity can also be applied on a general basis. Finally, in computing equilibrium long-run cost that accounts for different mixes of capacity, the suggested approach can be applied to any industry where there are tradeoffs between technologies that have different fixed and variable cost. Many suggest that their particular industry whether it be oil production, shipping, passenger airlines or electricity is highly complex and very difficult to analyze. As with other aspects of finance, these assertions and attempts to make things confusing are not necessary and are simply justifications of analysts in making their job seem important and impossible for others. All that is necessary to apply the techniques discussed below to other industries is data.

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